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THE FEASIBILITY OF REPLACING OR UPGRADING UTILITY DISTRIBUTION TRANSFORMERS DURING ROUTINE MAINTENANCE

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ABBREVIATIONS AND ACRONYMS

A	ampere
ac	alternating current
ANSI	American National Standards Institute
APPA	American Public Power Association
DOE	U.S. Department of Energy
EEI	Edison Electric Institute
FERC	Federal Energy Regulatory Commission
GDP	gross domestic product
h	hour
Hz	hertz
I^2R	resistive heating (current squared times resistance)
kV	kilovolt
kVA	kilovolt-ampere
kWh	kilowatt-hour
LCC	life-cycle cost
LF	load factor
LL	load loss
LSF	loss factor
m^2	square meter
MMT	million metric tons
MVA	megavolt-ampere
MW	megawatt
NEMA	National Electrical Manufacturers Association
NLL	no-load loss
O&M	operation and maintenance
OMB	Office of Management and Budget
PCB	polychlorinated biphenyl
T&D	transmission and distribution
TOC	total owning cost
V	volt
Vac	volt, alternating current

FOREWORD

This report contains the findings and recommendations of a study required by section 124 of the Energy Policy Act of 1992, which provides as follows:

> (c) Study of Utility Distribution Transformers. — The Secretary shall evaluate the practicability, cost-effectiveness, and potential energy savings of replacing, or upgrading components of, existing utility distribution transformers during routine maintenance and, not later than 18 months after the date of the enactment of this Act, report the findings of such evaluation to the Congress with recommendations on how such energy savings, if any, could be achieved.

The analysis contained in this report is significantly different in both methodology and purpose from the analysis that is under way to fulfill the provision in section 124(a) of the Energy Policy Act of 1992, which requires the Department of Energy to make a determination as to whether energy conservation standards for distribution transformers would be technologically feasible and economically justified and would result in significant energy savings. It should be noted that the analysis in this report addresses replacement versus refurbishment decisions concerning existing transformers that are on the utility side of the meter, as required by section 124(c) of the Energy Policy Act. The standards determination analysis concerns the manufacture and purchase of new distribution transformers on both the utility side of the meter and the customer side of the meter. Therefore, inferences from the findings of this report should not be made with respect to findings that will result from the standards determination analysis. While the analysis in this report contains very useful information from a national perspective, individual electric utilities should perform similar economic analyses using factors that are relevant to their operation.

ACKNOWLEDGMENTS

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This project could not have been accomplished without the assistance of NEMA, EEI, APPA, and the various electric utilities that provided valuable survey data on routine maintenance practices and new transformer purchases. The utility and transformer data and assistance provided by these organizations are gratefully acknowledged.

ABSTRACT

It is estimated that electric utilities use about 40 million distribution transformers in supplying electricity to customers in the United States. Although utility distribution transformers collectively have a high average efficiency, they account for approximately 61 billion kWh of the 229 billion kWh of energy lost annually in the delivery of electricity. Distribution transformers are being replaced over time by new, more efficient, lower-loss units during routine utility maintenance of power distribution systems. Maintenance is typically not performed on units in service. However, units removed from service with appreciable remaining life are often refurbished and returned to stock. Distribution transformers may be removed from service for many reasons, including failure, over- or underloading, or line upgrades such as voltage changes or rerouting. When distribution transformers are removed from service, a decision must be made whether to dispose of the transformer and purchase a lower-loss replacement or to refurbish the transformer and return it to stock for future use. This report contains findings and recommendations on replacing utility distribution transformers during routine maintenance, which is required by section 124(c) of the Energy Policy Act of 1992. The objectives of the study are to evaluate the practicability, cost-effectiveness, and potential energy savings of replacing or upgrading existing transformers during routine utility maintenance and to develop recommendations on ways to achieve the potential energy savings.

The analysis uses data provided by over 60 investor-owned utilities, which reveal that these utilities operate about one-third of the in-service capacity of utility distribution transformers. For a national perspective, the analysis uses these data and national average values to compute the average remaining transformer life that would economically justify transformer replacement. From this analysis it was determined that approximately 87 percent of transformer refurbishment is economically justified. While the analysis in this report contains very useful information from a national perspective, individual electric utilities should perform similar economic analyses using factors that are relevant to their operations. To ensure that all utilities are aware of the economics of these assessments, it is recommended that DOE provide this report to the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association and work with those associations in informing their member utilities of the economics of refurbishment versus replacement of distribution transformers when they are removed from service. It is also recommended that this report be provided to the Environmental Protection Agency to assist in its implementation of the Energy Star Transformer Program, which is part of the President's Climate Change Action Plan. Under this program, participating utilities will agree to purchase high-efficiency distribution transformers where economically warranted and will institute the early replacement of distribution transformers where economically warranted.

EXECUTIVE SUMMARY

Electrical energy is delivered to consumers by utility power transmission and distribution systems. The transmission network delivers power at high voltages (110 to 765 kV) from power plants to local distribution systems, where the electrical energy is transformed to lower primary distribution voltages (ranging from 4 to 35 kV). The high transmission voltages are used to transmit high levels of power over long distances. The high transmission voltages require lower currents, which reduce line losses, conductor material, and costs. Once the electrical power has reached the distribution system, it is transformed to lower primary distribution voltages that are more economical for the short distances within distribution systems. The primary distribution voltage is transformed by distribution transformers to lower secondary voltages (120 to 480 Vac) that are suitable for customer equipment. Distribution transformers are thus the final link in the chain of power transmission and distribution from the generating source to the customer.

It is estimated that there are 50 million distribution transformers in use in the United States. Of these, approximately 40 million are owned by electric utilities, and 10 million are owned and used by commercial and industrial customers.

Distribution transformer efficiencies steadily improved from the 1950s to the 1970s with the introduction of improved materials and manufacturing methods. Following the energy price shocks of the 1970s, some utilities began to use purchasing formulae that factored the effect of transformer efficiency into the purchasing decision. Manufacturers responded by tailoring their products to the energy evaluation factors specified by customers, a practice that continues to this day. Thus, it is now possible to purchase a variety of designs with trade-offs between energy losses and initial cost.

Distribution transformers are very reliable devices, with no moving parts and average lives over 30 years. A small percentage of transformers are removed from service every year because of failure, overloading, or line upgrades. Due to their long, trouble-free lives, some of the still-serviceable transformers that are removed from the system are being returned to service at a later date. Such "recycled" transformers often have higher losses than new, more efficient units.

About 92.5 percent of the energy generated at power plants is distributed to the ultimate consumer; the other 7.5 percent of the energy—approximately 229 billion kWh annually—is dissipated as losses in transmission and distribution (T&D) systems.[1,2] As can be seen in Fig. 1(a), utilities have made investments over time to decrease losses in their T&D systems and to improve system efficiency. The maximum efficiencies of distribution transformers have also improved over the same period. Figure 1(b) shows the average maximum efficiency for a 25-kVA distribution transformer. Approximately 26.6 percent of the average T&D losses are associated with distribution transformers. Thus, distribution

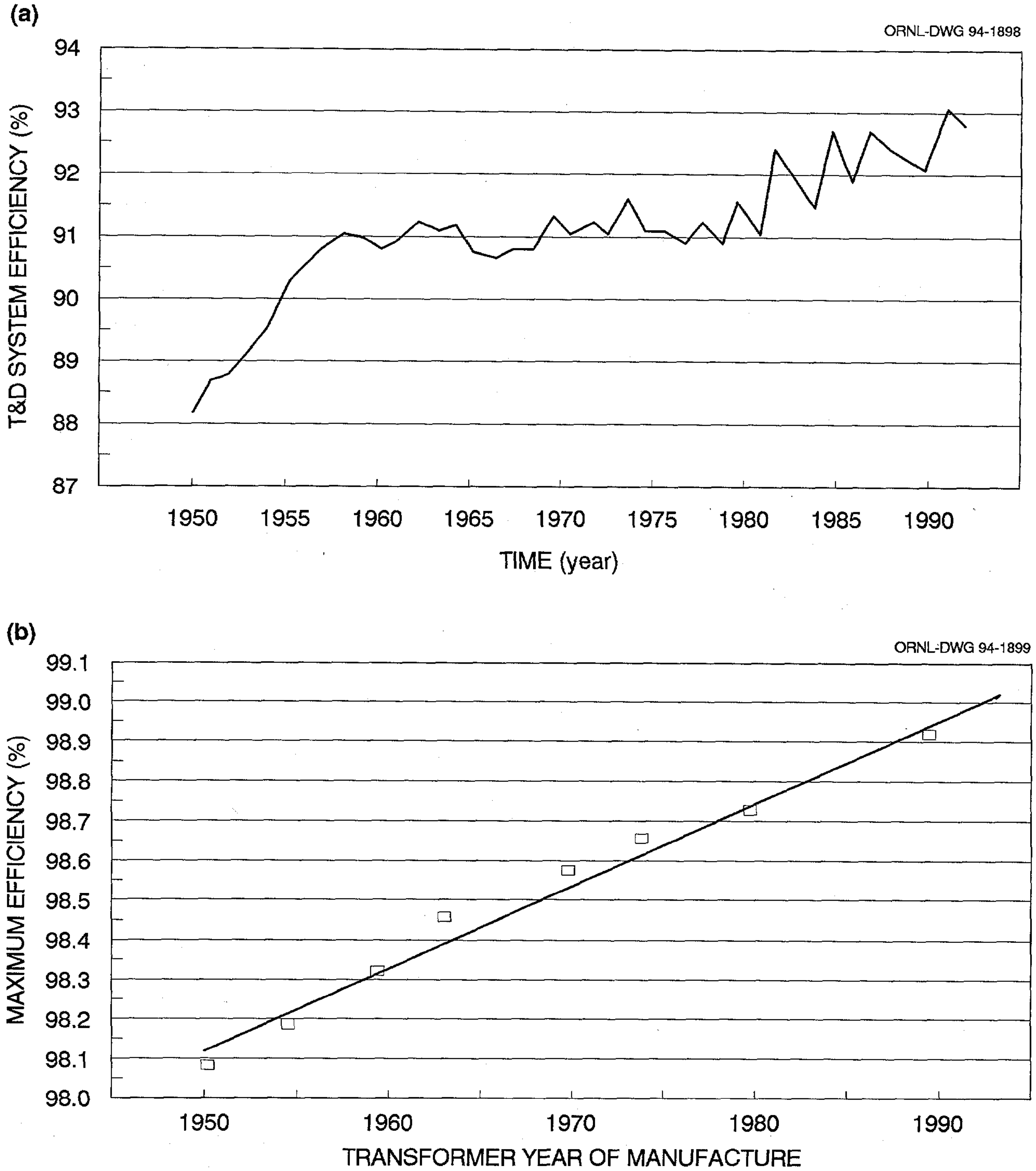

Fig. 1. Electric power transmission and distribution (T&D) system efficiency improvements: (a) T&D system efficiency; (b) maximum efficiency of a typical 25-kVA distribution transformer. *Sources:* (a) DOE, *Annual Energy Outlook, 1994*, DOE/EIA-0383(93); (b) for transformer data used to calculate (b), see Appendix E, Sect. E.6.

transformers account for approximately 61 billion kWh of the annual energy lost in the delivery of electricity. This is about 41 percent of total distribution system losses.[3,4,5]

Older transformers are being replaced over time by new, lower-loss units during routine utility maintenance of power distribution systems. As a result, the percentage of T&D losses associated with distribution transformers is decreasing each year. If there are cases where the replacement of older transformers with new low-loss units can be accelerated cost-effectively, then additional energy savings could be achieved. Energy savings from the use of more energy-efficient transformers would reduce generation requirements and would also contribute to the objectives of the President's Climate Change Action Plan by reducing greenhouse gas emissions.

The purpose of this report is to provide the results of an evaluation of the practicability, cost-effectiveness, and potential energy savings of replacing, or upgrading components of, existing utility distribution transformers during routine maintenance. The report contains recommendations on how such energy savings could be achieved. This is a requirement of section 124 of the Energy Policy Act of 1992.

Total System Replacement

A significant amount of energy, on the order of 44 billion kWh annually, could be saved if all distribution transformers were immediately replaced by new low-loss units (see Appendix B, Table B.8). However, immediate replacement of all distribution transformers is not practical. Using national average values, this approach to saving energy would not be cost-effective, since the benefit-to-cost ratio is only 0.6, significantly less than 1.0. Total system replacement is also impractical because it could not be accomplished during routine utility maintenance and because transformer manufacturers do not have the capacity to produce the large number of transformers required to meet such a high demand, which would be ten to twenty times normal.

Routine Utility Maintenance

Information was collected from utilities to determine general maintenance practices for distribution transformers. Most utilities have a distribution transformer maintenance program that involves inspection and testing, minor and/or major refurbishment, and retirements. Distribution transformers are removed from service for a variety of reasons: because transformers have become overloaded, because they have failed as a result of lightning or traffic accident damage, because of lane relocation due to street or highway construction, because of voltage upgrade, and so on. The removed units are delivered to the transformer maintenance department, where they are examined to determine if they are to be refurbished and returned to stock or retired to scrap. Refurbishments include both minor in-house activities and major maintenance such as rewinding the transformer. The number of distribution transformers rewound is very small according to a survey of utilities.

Based on survey information, most of the refurbishments occur on transformers less than 20 years old with a significant amount of remaining life, and for this reason, these transformers are not good candidates for cost-effective replacement. Many utilities have an age criterion beyond which they would not consider a transformer for refurbishment. Of those utilities with an age criterion for retirement (about 49 percent of the utilities surveyed), the retirement age ranges from 14 to 35 years, with the average being about 25 years.

Cost-Effectiveness of Early Transformer Replacement

The economics of early transformer replacement weighs the life-cycle costs of replacing an existing transformer with a new transformer versus the life-cycle costs of refurbishing and continuing to use the existing transformer with replacement occurring later. The costs of the refurbishment option include the expense of refurbishment and the capital costs of later replacement as well as the costs of energy losses for both the refurbished transformer and its eventual replacement. The costs of early replacement include the capital costs and the cost of energy losses. The comparative evaluation is driven by several factors. *Two extremely important factors are the assumption of the remaining life of the refurbished transformer and the cost of refurbishment and reinstallation.* The energy costs of the two alternatives vary with the differences in the refurbished and new transformer no-load and load losses and with the rates at which these losses are valued. The rates of loss valuation are determined through valuing the cost of capacity and production costs that are avoided as a result of reducing a transformer's no-load and load losses. This study portrays a "national perspective" on these rates based on average values for incremental capacity costs and production costs.

The life-cycle cost comparison is made for 11 types of transformers encompassing a range of size and design variables. Assumptions about transformer energy losses for refurbished transformers were based on losses typical of the transformer's vintage. Assumptions about the costs for new transformers and their rates of energy losses were based on a survey of 67 utilities. This survey also provided average values for refurbishment and reinstallation costs. The life-cycle cost calculation was iterated to find the remaining life for the refurbished transformer that equated the life-cycle costs of the alternatives. This break-even point for the remaining age was used to find the corresponding break-even age of the refurbished transformer. This determined the cost-effective replacement criteria. In other words, all transformers older than this break-even age could be cost-effectively replaced, and all transformers younger than this age could be cost-effectively refurbished and continue in use. The average break-even transformer age is about 24 years (approximately 11 years of remaining life), based on the loss evaluation derived from the national perspective referred to above.

On the basis of the transformer age criterion, the results from the survey of utilities were used to estimate the percentage of refurbished transformers for which early replacement would be cost-effective. This estimate indicated that from the national perspective about 13 percent of refurbished transformer capacity could be cost-effectively replaced. Therefore, the vast majority (87 percent) of utility refurbishment decisions that would be considered are justified from a national perspective. The differences between the utility practices reported and the assessments contained in this report are not significant. Most transformers that now receive routine maintenance and are returned to service are recent-vintage transformers. This makes them economically unattractive candidates for early replacement because they have approximately the same rate of energy losses as the new transformers that would replace them.

Potential Cost-Effective Energy Savings

Using the national perspective estimate discussed previously, the potential energy savings for cost-effective early replacement over and above the replacements currently underway at utilities, are relatively small. The estimated savings in the first year would be 0.05 billion kWh. If cost-effective early replacements began in 1995, the total cumulative energy savings would be 0.55 billion kWh by the year 2000. The average annual rate of savings over 25 years would be about 50 percent of the annual generation of a 50-MW power plant operating at 65 percent capacity, or enough electricity to supply the residential needs for a population of about 40,000. These potential energy savings are quite small. One reason is that only a small fraction of in-service transformers are being refurbished and only a small fraction of these refurbishments would be cost-effective for early replacement. In other words, most cost-effective refurbishments and replacements are already being undertaken by utilities.

Reduction in Greenhouse Gas Emissions

If all utilities adopted cost-effective accelerated retirement policies based on the national perspective, the cumulative additional reduction of carbon emissions by the year 2000 would be 0.094 million metric tons (MMT). The average annual reduction rate over 25 years would be 0.025 MMT.

Practicability Issues

The cost-effective replacement or upgrading of distribution transformers can be accomplished within the framework of existing utility practices. Many utilities are currently replacing or upgrading transformers in cost-effective strategies tailored to those utilities. This strategy often involves an age criterion for transformer retirements or a loss criterion whereby losses are determined from records or loss measurements. A loss criterion is preferred because losses can be evaluated with all relevant economic data in order to determine the transformer's disposition. However, many utilities are not equipped to measure transformer losses. Utilities could easily accelerate the replacement of older distribution transformers by adopting a retirement age that reflects cost-effective replacements. If all utilities adopted a cost-effective retirement criterion that matched the analysis contained in this report, the additional demand for distribution transformers would be about 4 percent of the new units now being purchased. Transformer manufacturers could easily meet this small additional demand.

Conclusions

Judging from the survey data obtained from utilities and the analyses contained in this report, electric utilities are making reasonable decisions regarding the replacement or refurbishment of distribution transformers that are removed from service. The comparison of the replacement practices by utilities in the survey and other national analyses contained in this report indicates that on average about 9 out of 10 utility refurbishment decisions are economically justified from a national perspective. This assumes replacement is with average-loss new transformers.

Recommendations

The information and the analyses contained in this report reveal that many of the utilities surveyed are making reasonable assessments regarding replacement or refurbishment of distribution transformers. This does not mean that all utilities are making optimum economic assessments based on factors that are relevant to their operations. In addition, as discussed in Appendix E, there is considerable variation among utilities in key factors for these decisions. Therefore, individual utilities should perform similar economic analyses using factors that are relevant to their operations. To ensure that all utilities are aware of the economics of these assessments, it is recommended that DOE provide this report to the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association and work with those associations in informing their member utilities of the economics of refurbishment versus replacement of distribution transformers when they are removed from service. It is also recommended that this report be provided to the Environmental Protection Agency to assist in the implementation of the Energy Star Transformer Program, which is part of the President's Climate Change Action Plan. Under this program, participating utilities will agree to institute the early replacement of distribution transformers where economically warranted.

1. INTRODUCTION

1.1 BACKGROUND

Electrical energy is delivered to consumers by utility power transmission and distribution systems. The transmission network delivers power at high voltages (110 to 765 kV) from power plants to local distribution systems, where the electrical energy is transformed to lower primary distribution voltages (ranging from 4 to 35 kV). The high transmission voltages are used to transmit high levels of power over long distances. The high transmission voltages require lower currents, which reduce line losses, conductor material, and costs. Once the electrical power has reached the distribution system, it is transformed to lower primary distribution voltages that are more economical for the short distances within distribution systems. The primary distribution voltage is transformed by distribution transformers to lower secondary voltages (120 to 480 Vac) that are suitable for customer equipment. Distribution transformers are thus the final link in the chain of power transmission and distribution from the generating source to the customer. It is estimated that there are approximately 40 million distribution transformers owned by electric utilities in use in the United States.

Distribution transformer efficiencies steadily improved from the 1950s to the 1970s with the introduction of improved materials and manufacturing methods. Following the energy price shocks of the 1970s, some utilities began to use purchasing formulae that factored the effect of transformer efficiency into the purchasing decision. Manufacturers responded by tailoring their products to the energy evaluation factors specified by customers, a practice that continues to this day. Thus, it is now possible to purchase a high-cost, high-efficiency transformer or a unit with a lower first cost and lesser efficiency.

Distribution transformers are very reliable devices, with no moving parts and average lives over 30 years. A small percentage of transformers are removed from service every year because of failure, overloading, or line upgrades. Due to their long, trouble-free lives, still-serviceable transformers that are removed from the system can be returned to service at a later date without regard to their loss performance. Such "recycled" transformers often have higher losses than new, more efficient units.

About 92.5 percent of the energy generated at power plants is distributed to the ultimate consumer; the other 7.5 percent of the energy—approximately 229 billion kWh annually—is dissipated as losses in transmission and distribution (T&D) systems (based on 1992 T&D losses).[1,2] If subtransmission lines are included in the distribution system, about 35 percent of the losses occur in the transmission system and 65 percent of the losses occur in the distribution system.[3] This ratio of losses is typical of the Tennessee Valley Authority (TVA), which meters sales to municipalities and cooperatives at the input of their distribution systems. The TVA T&D system is considered typical of large utilities in the United States. As can be seen in Fig. 1.1(a), utilities have made investments over time to decrease losses in their T&D systems and to improve system efficiency. The maximum efficiencies of distribution transformers have also improved over the same period. Figure 1.1(b) shows the average maximum efficiency for a 25-kVA distribution transformer. Approximately 41 percent of the average distribution system losses are associated with distribution transformers according to two studies involving three utilities.[4,5] Thus, distribution transformers account for approximately 61 billion kWh of the annual energy lost in the delivery of electricity.

Older transformers are being replaced over time by new, lower-loss units during routine utility maintenance of power distribution systems. As a result, the percentage of T&D losses associated with distribution transformers is decreasing each year. If there are cases where the replacement of older transformers with new low-loss units can be accelerated cost-effectively, then additional energy savings could be achieved. Energy savings from the use of more energy-efficient transformers would reduce generation requirements and would also contribute to the objectives of the President's Climate Change Action Plan by reducing greenhouse gas emissions.

The purpose of this report is to provide the results of an evaluation of the practicability, cost-effectiveness, and potential energy savings of replacing, or upgrading components of, existing utility distribution transformers during routine maintenance. The report contains recommendations on how such energy savings could be achieved. This is a requirement of section 124 of the Energy Policy Act of 1992.

1.2 STUDY APPROACH

This study consists of three major elements: database development, model development, and technical and economic analyses to derive estimates of the potential energy savings and assess the impacts of accelerating transformer retirements. Analyses used national averages of the data. Each stage is discussed briefly below.

- ***Database Development.*** Collecting and processing data was a major part of the study. Data was provided by the National Electrical Manufacturers Association (NEMA), the Edison Electric Institute (EEI), the American Public Power Association (APPA), manufacturers, and selected utilities. The survey forms circulated by EEI and APPA to their member utilities are reproduced in Appendix A. Information from 68 electric utilities was used in the analysis. In addition, Federal Energy Regulatory Commission (FERC) Form 1, Energy Information Administration (EIA) information, and trade journals were used. The basic information required included historical information on the distribution transformer population by sizes and losses, losses and costs of new

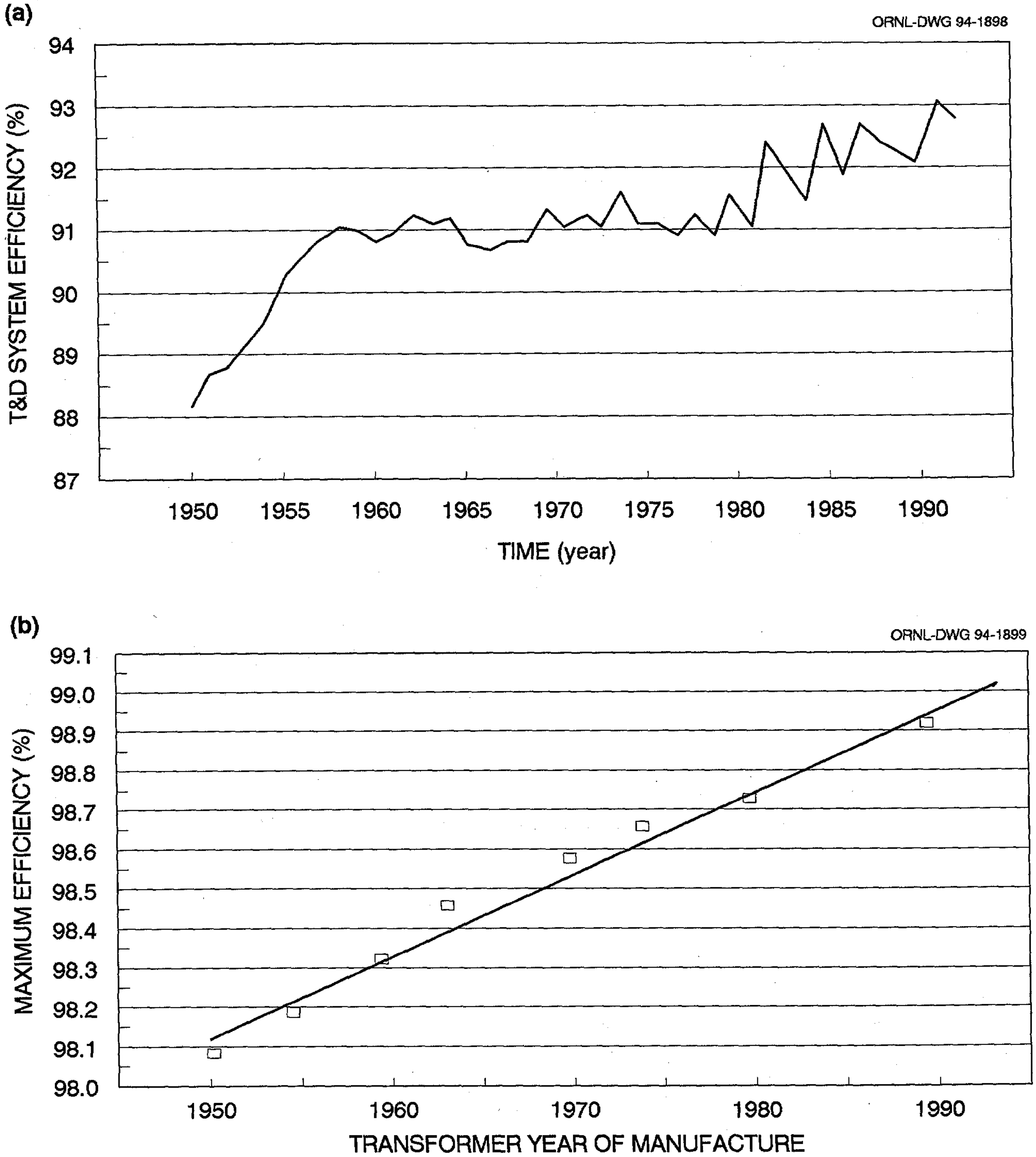

Fig. 1.1. Electric power transmission and distribution (T&D) system efficiency improvements: (a) T&D system efficiency; (b) maximum efficiency of a typical 25-kVA distribution transformer. *Sources:* (a) DOE, *Annual Energy Outlook, 1994*, DOE/EIA-0383(93); (b) for transformer data used to calculate (b), see Appendix E, Sect. E.6.

transformers, and utility maintenance practices, including costs and criteria for retiring old units.

- *Model Development.* Special models had to be developed to age transformers (determine failures over time) to obtain an estimate of the present in-service population (see Appendix B), to conduct an economic analysis from a national perspective, and to estimate the potential energy savings. Existing economic models were used for impact evaluations.

- *Analysis.* The technical and economic analyses provided estimates of transformer loading factors, losses, and remaining life for units that had been in service a given number of years, and identified cases where replacement would be cost-effective. The cost-effective cases and other bounding cases were used in an energy savings analysis.

1.3 SCOPE AND CONTENT

This report documents the assumptions, models, data, and conclusions of this study on the feasibility of accelerating the replacement of older distribution transformers with new, lower-loss units. This study is limited to the consideration of transformers replaced during routine electric utility maintenance. Data on electric utility maintenance practices are available from an industry survey and from six selected surveys that provided more in-depth information. (See Appendix A.) Only oil-filled distribution transformers were considered, since about 99 percent of all utility distribution transformers are oil-filled. Dry-type transformers are normally located inside buildings and are owned by commercial and industrial customers. In addition, transformers used for series streetlight circuits were not considered because these circuits are being replaced over time by modern, more efficient lighting techniques. Both pole-mount single-phase and pad-mount single- and three-phase transformer types were considered. Most of the transformers that presently undergo routine utility maintenance are single-phase pole-mount units.

Section 2 describes the routine maintenance practices that electric utilities perform for distribution transformers, and Section 3 discusses the technical characteristics and important parameters of distribution transformers. Cost-effective replacement strategies are described in Section 4, and the potential energy savings impacts as well as other practicality issues are discussed in Section 5.

2. ROUTINE MAINTENANCE BY UTILITIES

2.1 GENERAL MAINTENANCE PRACTICES

Information was collected from 68 electric utilities to determine general utility maintenance practices for distribution transformers. Typically, maintenance is only performed when distribution transformers are removed from service. The maintenance program used by most utilities consists of the following basic elements: inspection and testing, minor in-house refurbishments, major refurbishments in the form of rewinding transformers, and retirements. A flow diagram of the maintenance process is shown in Fig. 2.1. Distribution transformers are removed from service for a variety of reasons: for example, transformers may be overloaded, may have failed because of lightning or traffic accident damage, or may be removed because of voltage upgrades or line reroutes due to street or highway construction. Distribution transformers are not normally removed from service because of age alone. The removed units are delivered to the transformer maintenance department, where they are examined to determine if they can be refurbished and returned to stock or should be retired to scrap. Refurbishments range from minor in-house repair to major maintenance such as rewinding. Although some utilities have the capability to rewind transformers, many send transformers to a rewinding plant for major refurbishments. However, rewinding is a very small part of the overall refurbishment activities (less than 2 percent of refurbished transformer capacity), according to an industry survey.

2.2 INSPECTION AND TESTS

Removed transformers are delivered to the transformer maintenance department, where inspections and tests are conducted to determine the extent of repairs that will be necessary to return units to service. Transformers judged to be beyond repair are retired and disposed of as scrap. The inspection and testing program varies from utility to utility. In general, utilities employ several of the following tests:

- visual inspection to identify leaky gaskets, broken bushings, corrosion, etc.;
- insulation power-factor or resistance tests;
- oil tests for dielectric quality and/or the presence of contaminants such as water or polychlorinated biphenyls (PCBs);
- winding turns ratio tests;
- rated voltage and current tests; and
- no-load-loss and load-loss tests.

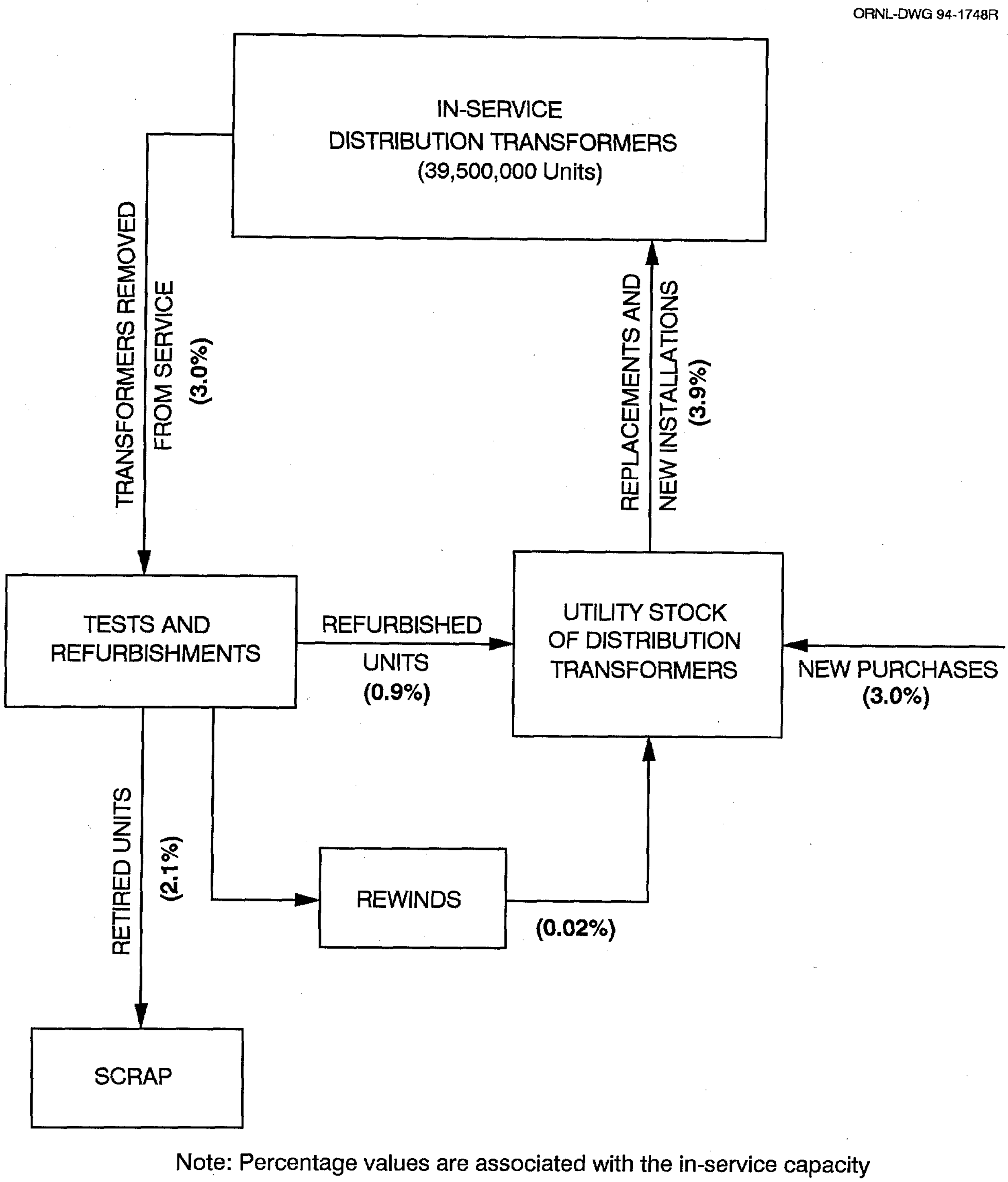

Fig. 2.1. Flow diagram for routine maintenance of utility distribution transformers. The estimated in-service units is based on adjustments to the FERC Form 1, an annual report required of major utilities.

The results of these tests are used along with age and economic considerations to determine if a transformer is to be refurbished, scrapped, or rewound.

2.3 RETIREMENT CRITERIA

The decision to retire a transformer is based on a number of factors. Failure of one or more of the electrical and oil tests, PCBs in the oil, and age were listed most often in the survey as reasons for retirement. Transformers with incorrect primary voltage ratings due to system voltage changes are also retired or sold. Approximately 49 percent of the utilities that participated in the survey have age criteria for retiring distribution transformers. Of those in our survey that did, the retirement age ranged from 14 to 35 years, and the average age was near 25 years, with a standard deviation of about 5 years. The retirement criteria determines whether a transformer that has been taken off-line should be considered for refurbishment or automatically scrapped and should not be confused with the average transformer life (retirement age) which is about 32 years (see Appendix D). On average, in terms of transformer capacity, about two-thirds of the units removed from service are retired. This retirement rate varies from utility to utility, from about one-third to nearly 100 percent of the transformers removed from service. The annual retirement rate is 1.7 percent of the in-service capacity, and the number of units retired is 2.0 percent of the total in-service distribution transformers.

2.4 REFURBISHMENTS AND REWINDS

Transformers that are not retired are refurbished and returned to stock. Minor refurbishments may involve nothing more than updating the transformer's historical record and replacing connectors, nuts, etc., as needed. Other units may need gaskets or bushings replaced or the oil changed and the coils dried out. Some utilities routinely change or clean the transformer oil. Major refurbishments such as rewinding the transformer are often performed by a rewinding firm. Appendix C provides additional information about rewinding transformers. The rewound transformer capacity is a very small portion of the total refurbished capacity (less than 2 percent, according to industry survey results).

The total annual refurbished transformer capacity, including rewound units, is approximately 1.0 percent of the in-service capacity. Over 47 percent of the refurbished transformers are less than 10 years old, about 34 percent are between 10 and 20 years old, 17 percent are 20 to 30 years old, and less than 2 percent are older than 30 years.

2.5 NEW PURCHASES

New distribution transformers are purchased to meet the demands of new growth, replace units that are retired, and replenish the stock. The average number of new purchases is 3.0 percent of the number of in-service distribution transformers.[6] The number of purchases for new installations is about 0.9 percent of the number of in-service distribution transformers. The number of new purchases used to replace retired transformers is 2.1 percent of the number of in-service units.

Many electric utilities tend to purchase new transformers that provide the lowest total owning cost (TOC)* for their system. Loss evaluation factors (capitalized energy costs) associated with no-load core losses and full-load winding losses at the nameplate rating (excluding core losses) are developed using the utility's cost of energy and other economic parameters. The core loss evaluation factor and the winding loss factor are often called the A and B factors, respectively. This information is provided to the transformer manufacturers for a bid.

2.6 SUMMARY

Electric utilities routinely purchase, refurbish, and retire distribution transformers. Table 2.1 summarizes the annual average levels of new purchases, refurbishments, and retirements for utility distribution transformers.

*The total owning cost (TOC) is a capitalized value, making the first cost of the transformer comparable to the lifetime energy costs.

Table 2.1. Annual utility distribution transformer activities

Activity	Percent of in-service capacity	Percent of in-service units
New purchases[a]	4.2	3.0
Retirements[b]	1.7	2.1
Refurbishments[b]	1.0	0.9
New installations[c]	2.5	0.9

[a] Based on adjusting FERC Form 1 report of new distribution transformer purchases (1.2 million in 1992) and a total of 39.5 million utility distribution transformers in service, and assuming an average size of 58.6 kVA for new transformers. (See Appendix B.)
[b] Based on 1993 utility industry survey.
[c] Derived from new purchases less retirements.

3. DISTRIBUTION TRANSFORMERS

3.1 INTRODUCTION

The transmission and distribution (T&D) of alternating current (ac) electric power requires the conversion of voltage and current levels to match the desired application. This conversion, accomplished by transformers, represents a significant portion of the investment in the T&D system. While the transformers used in the T&D system are acknowledged to be very efficient, the cumulative effect of the losses of a large number of distribution transformers can represent a substantial cost to the system. The major objective of transformer design is to achieve the lowest possible TOC to owners and operators; this requires a trade-off between the capital cost of transformers and the resultant cost of the transformer losses. Moreover, the strong interaction and interdependence of the design parameters require careful trade-offs to accomplish this objective. These trade-offs often result in what may appear to the casual observer to be completely different concepts.

As indicated in Section 1, this report addresses those transformers owned by electric utilities that perform the final transformation from utility distribution voltages (4.0–34.5 kV) to final utilization voltage (120/240-V single-phase; 120/208-V or 278/480-V three-phase); hence, the obvious designation "distribution transformer." These distribution transformers range in size from about 5-kVA single-phase to 2500-kVA three-phase transformers. In general, distribution transformers operate over a wide range of loads, with substantial portions of the day and year near minimum load. As shown in Section 3.2, this light loading increases the importance of losses at low-load levels. Because of the extreme variation in load, distribution transformers are sometimes called "all-day" or stand-by transformers, since energizing current must always be present, even without load. The vast majority of distribution transformers on the utility-owned distribution system are the oil-filled type, as opposed to dry type; hence, the discussion in this report is limited to oil-filled distribution transformers. Dry-type transformers are generally used by large customers within facilities and are not considered a part of the utility distribution system, since these are located on the customer side of the meter.

3.1.1 The Ideal Transformer

There are three basic elements to a transformer: the primary winding, the secondary winding, and the core. Figure 3.1 indicates the key elements pictorially. The two windings are coils of wire wound around a core of high-magnetic-permeability material. By definition, the primary winding is the one connected to the electrical source, while the secondary winding is connected to the output or load. The core may be made of silicon steel, nickel alloy, or amorphous metal and provides a path for the magnetic flux that links all the

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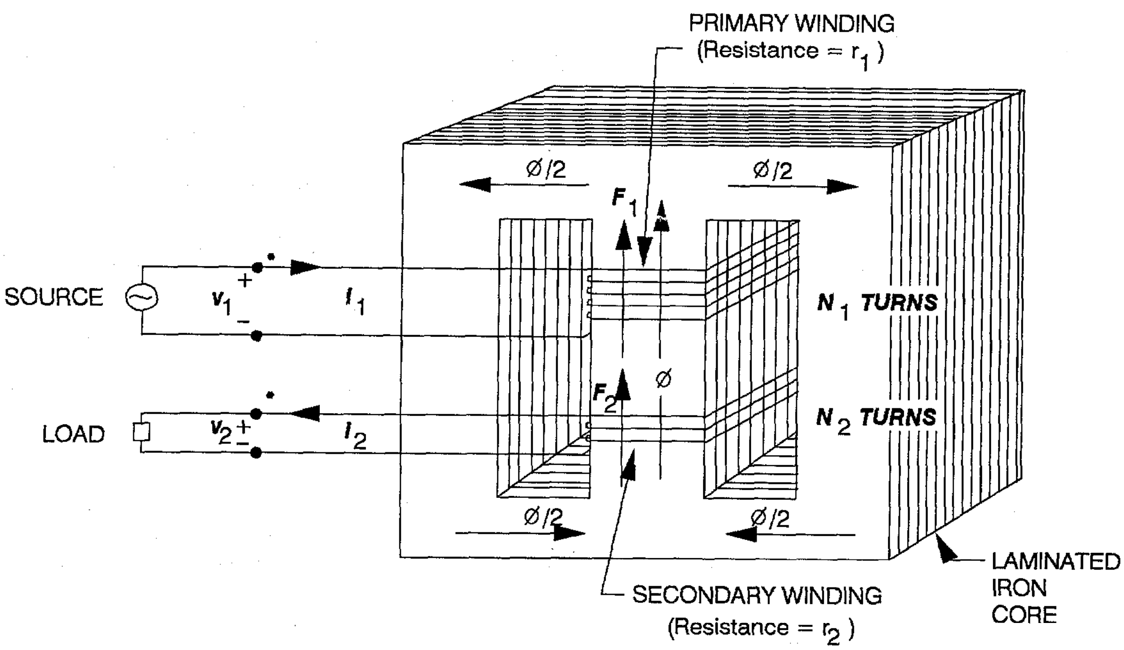


Fig. 3.1. Major internal elements of a transformer.

windings. An alternating flux is set up in the core when the primary winding is connected to an ac voltage source. This alternating flux induces voltage in all windings that is proportional to the number of turns in the specific winding (Faraday's law). In the ideal transformer there are no losses or leakage flux, and the ratio of the voltages induced is equal to the ratio of the number of turns in the respective windings. For example, a transformer with a 1000-Vac source applied to 100 turns in a primary winding will induce a voltage of 100 V in a secondary winding with only 10 turns. By selecting the proper turns ratio, the designer can determine the ratio of input to output voltages. Simply, the volts/turn is constant in each winding.

Since the ideal transformer neither stores nor loses energy, the power input to the primary winding must equal the power output to the secondary winding. As the power input is the product of the voltage and current on the primary side, the power output must be equal to the product of the voltage and current on the secondary side. This implies that the ratio of the primary and secondary current is inversely proportional to the turns ratio. Hence, the ideal transformer simply changes the voltage between the windings in proportion to the turns ratio and changes the current in inverse proportion. In the example given in the previous paragraph, the secondary current must be 10 times the primary current. Assuming that the transformer's rating is 5 kVA, then the primary current is 5 A, and the secondary current is 10 times this, or 50 A or $I_1N_1 = I_2N_2$ since the volts/turns are constant.

Obviously, transformers are not ideal, and while the modern transformer very closely approaches the ideal, there are losses. Specifically, there is a voltage drop through the transformer under load so that the voltage ratio is not exactly equal to the turns ratio and an excitation current proportional to the supply voltage flows in the transformer even when no-load current is present. The excitation current reflects the presence of no-load losses, while the losses at load are in direct proportion to the product of the square of the current and the winding's effective electrical resistance. For these reasons, the turns ratio does not match the ideal relationship. Details of these loss mechanisms are discussed more fully below.

In the transformer depicted in Fig. 3.1, the windings are separated to avoid confusion. In reality, the lower-voltage windings are placed next to the core and extend over the entire core leg, with the high-voltage windings placed outside and over the low-voltage windings. Since the core is at ground potential, this simplifies the problem of insulating the high voltage from the core material. Clearly, the windings must be insulated from ground and from low to high voltage. In addition, voltage drop in the windings requires an insulation from turn to turn and layer to layer of each winding (and between phases in three-phase units). The space required by the insulation effectively increases the size of both coil and core and hence the transformer's design volume. The amount of insulation required is dependent upon both steady-state and transient voltage levels, and increases with the transformer's rated voltage. Since the transformer is an ac device, a small loss (often ignored in distribution transformer designs) is present in the insulation. This loss, which is called the dielectric loss, and other less significant losses may require more careful attention as losses are further reduced in distribution transformers.

There are two basic methods of winding transformers: (1) the core form, in which the two sets of windings surround a core, and (2) the shell form, in which a single set of windings is surrounded by core material, as shown in Fig. 3.1. There is essentially no inherent difference in cost or performance between the two designs, and the design chosen is somewhat dependent upon the setup of the manufacturing facility.

3.1.2 Major Transformer Loss Mechanisms: No-load and Load Losses

As noted, the ideal transformer provides an excellent approximation to actual transformer behavior; however, detailed design and performance studies must take into account the departure from the ideal. There are essentially two major types of losses in transformers, no-load losses and load losses.[7]

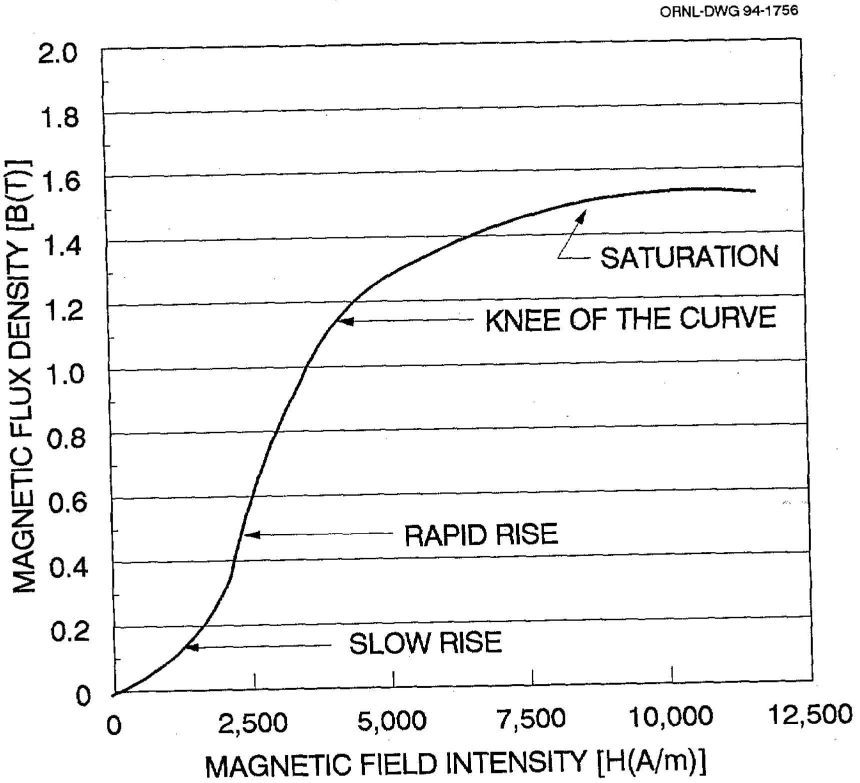
No-load losses. No-load losses are those losses required in the excitation of the transformer. No-load losses include dielectric loss, conductor loss due to excitation current, conductor loss due to circulating current, and core loss. The dominant no-load loss is core loss, which is associated with the time-varying nature of the magnetizing force and results from hysteresis and eddy currents in the core materials. Core losses are dependent upon the excitation voltage and may increase sharply if the rated voltage of the transformer is exceeded. There is also some inverse dependence on core temperature.

Hysteresis losses in transformer core materials occur because the core materials resist realigning the magnetic domains in the material. The power required to overcome this reluctance and change magnetic alignment is dependent upon the operating frequency, the amount and type of core material, and the magnitude of the magnetic flux density. Furthermore, the magnitude of hysteresis loss is dependent upon flux density, which is, in turn, dependent upon terminal voltage and the number of winding turns. This interdependence is referred to as the "machine equation" and is a consequence of Faraday's law of electromagnetic induction. At 60 Hz, this relationship is expressed by the equation $B = E/(266.57NA)$, where B = magnetic flux density (tesla), E = the terminal voltage (rms volts), N = the number of turns in the winding, and A = the cross-sectional area of the core (m^2).

The initial magnetization curve and a typical hysteresis curve for a ferromagnetic material are shown in Fig. 3.2. Clearly, the relationship between magnetic flux density and magnetic field intensity is nonlinear. For maximum operating performance at minimum capital cost, it is generally desirable to operate the transformer just below the knee, or bend, in the magnetization curve. Care must be taken to ensure that the operating voltage levels do not push the transformer into the saturation region of the curve beyond the knee, since this sharply increases losses and harmonics. Alternatively, reduction of the peak operating flux, while reducing hysteresis losses, results in the need for a larger cross section of core material and can thus increase transformer capital cost, weight, and volume. The use of different core materials also impacts size and capital cost.

The alternating flux induces in the core material small circulating currents much like eddies in a stream. These eddy current losses in the core materials represent the other major component of core losses and are functions of the operating frequency, the flux density, the volume of core material, and the resistivity of the core material. To reduce eddy current losses, the core materials are selected for high resistivity and are formed into thin sheets called laminations which are separated by thin layers of insulating oxide coating and oriented to minimize the induced currents. These actions increase capital cost by increasing the core volume, the materials cost, and the assembly labor costs. Similarly, decreasing eddy currents by lowering the flux density increases the core material requirements and potentially the capital cost, weight, and volume.

The resistivity of the core material has traditionally been increased by alloying iron and silicon and cold-rolling the materials into thin laminated sheets of 7- to 12-mil thickness. These materials are then heat-treated to reduce hysteresis losses. While great strides have been



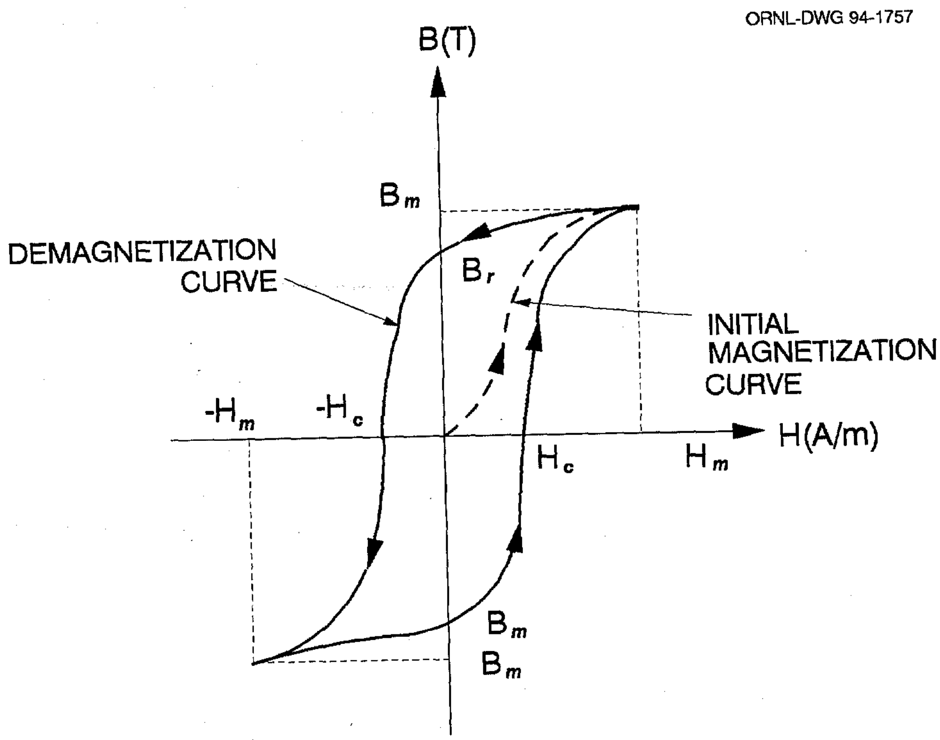


Fig. 3.2. Typical initial magnetization curve (*top*) and typical hysteresis curve (*bottom*) for ferromagnetic material.

made in reducing the losses in high-silicon-steel materials, a technique for producing materials in which the iron atoms are randomly oriented (amorphous metal) has been developed. In this process, a molten alloy of iron, silicon, and boron is allowed to spill in a ribbon onto a rapidly rotating drum, where it is chilled at the rate of about a million degrees per second, forming a glasslike ribbon of material about 1-mil thick without crystalline structure. This material has good magnetic properties, low inherent hysteresis losses, and high resistivity. The very thin laminations greatly reduce eddy currents, but their extreme brittleness and the difficultly in handling them adds to the assembly cost. Transformer cores made of this amorphous core material have less than 25 percent of the losses per pound of material demonstrated by the best transformer cores made of high-grade silicon steel. The drawbacks of the amorphous core material include increased core costs, increased difficulty in fabrication, increased core volume and weight, and reduced saturation flux density. While the present capital cost penalty relative to high-grade silicon steel appears to be about 25 percent, the industry is optimistic that this penalty can be reduced to less than 10 percent.[8]

Load losses. Those losses that are incident with the carrying of load are referred to as load losses. Unlike no-load losses, which are constant and always present, load losses vary with the square of the load carried by the transformer and include the resistive heating (I^2R) losses in the windings due to both load and eddy currents; stray loss due to leakage fluxes in the windings, core clamps, and other parts; and the loss due to circulating currents in parallel windings and parallel winding strands. For distribution transformers, the major source of load losses is the I^2R losses in the windings.

Load losses can be reduced by selecting lower-resistivity materials (such as copper) for the windings, by reducing the total length of the winding conductor, and by using a conductor with a larger cross-sectional area. Eddy currents are controlled by using subdividing and insulating the conductor and by conductor shape and orientation. Clearly, this involves a combination of material and geometric options which also depend upon the core dimensions.

As a general rule, reducing no-load and load losses involves trade-offs with capital cost, volume, and weight. Larger, heavier transformers are generally more efficient but are also more expensive. Moreover, for a given capital cost, volume, and weight, transformers of the same voltage and kilovolt-ampere rating trade off no-load against load losses. This is illustrated conceptually by the cost versus losses surface in Fig. 3.3, which in reality is a set of discrete points established by available core dimensions. Since load losses vary with the square of the load, transformer efficiency is load-dependent. Furthermore, it can be shown

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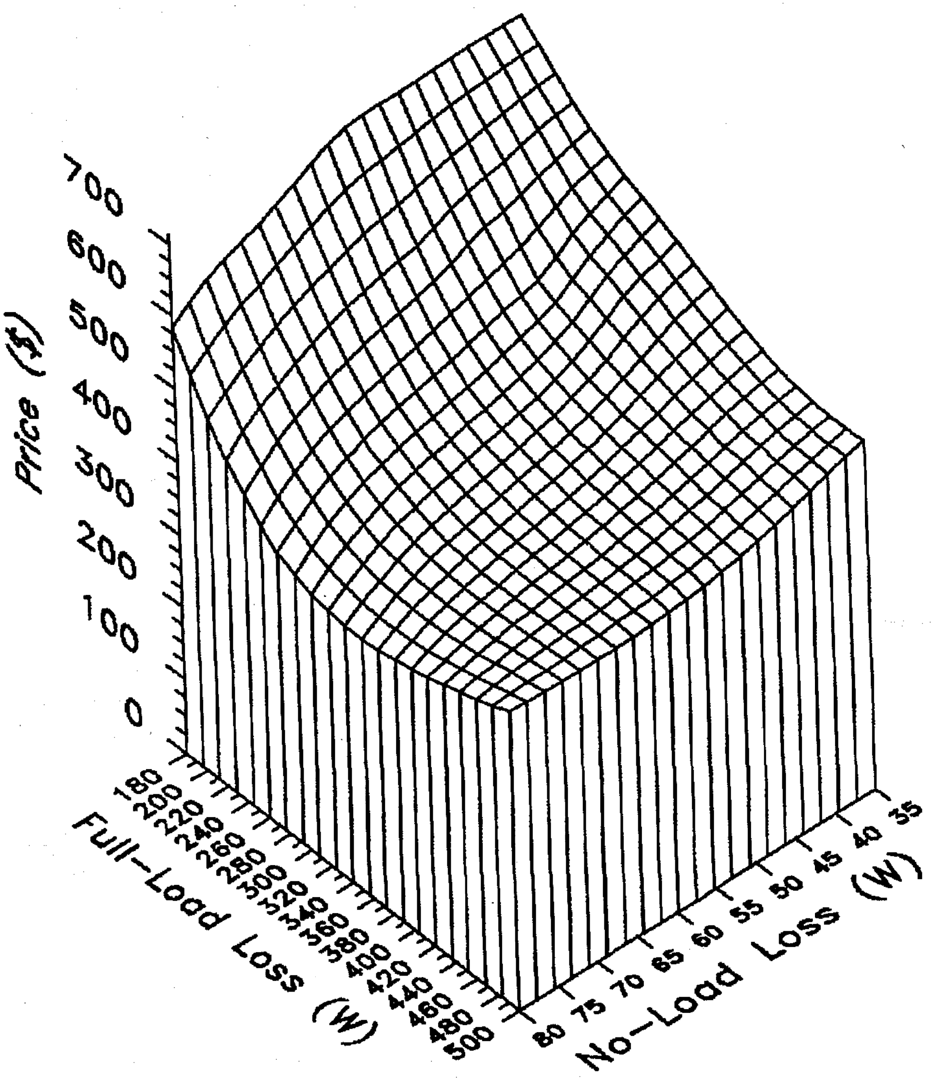

Fig. 3.3. Surface of cost vs losses for a typical 25 kVA distribution transformer. *Source:* National Electric Manufacturers Association.

mathematically that maximum efficiency occurs at the load point for which load losses and no-load losses are equal.* Most distribution transformers are generally lightly loaded for relatively long periods and are designed with lower no-load losses to operate with maximum efficiency at 25-50 percent load (Fig. 3.4). The curves shown in Fig. 3.4, which are typical of distribution transformers, illustrate two different applications: (1) the first—called low no-load loss (NLL), high load loss (LL)—is for transformers that would be expected to be lightly loaded (low-load factor); and (2) the second—labeled moderate NLL, low LL—would be applied to a transformer with a higher load factor (load factor = average load / peak load). The curves are easily plotted using equations of the type illustrated in the previous footnote, inputting values for the nameplate rating, load losses, and no-load losses. The effect on total losses is indicated by Fig. 3.5, which illustrates the general nature of this trade-off.

3.2 TRANSFORMER LOSSES, LOADING, AND LIFE

Typical values for losses in distribution transformers are given in Table E.1 by size and age. As a result of improved performance in core materials from both silicon steel and amorphous core materials and increased demand for lower TOCs, transformer losses have decreased steadily since the 1950s.

The TOC evaluation methodology,[7] which has been used by utilities for a number of years, provides a balance between cost of purchase and cost of energy losses. The wide range of no-load evaluation values (A factor) and load loss evaluation values (B factor) indicate the broad diversity of utility energy and capital expenses. While the individual A and B factors reflect the cost of no-load and load losses to the utility, it is interesting to observe that for transformers of equal cost (effectively eliminating the capital cost) the ratio of A/B characterizes the relative importance to utilities of no-load losses relative to load losses. Low values of A/B seem to favor transformer designs with lower load losses, while high values seem to favor designs with lower no-load losses.

Determination of both the size in kilovolt-amperes and the load factor of distribution transformers is an important task. Methodologies have been developed to enable utilities to

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*Efficiency (η) is defined as output energy divided by the sum of output energy and losses. Assuming constant terminal voltage,

$$\eta = \frac{S \cos\Theta}{[S \cos\Theta + \text{core losses} + \text{load losses} \times (|S|/S_B)^2]} \, ,$$

where S = kVA load, S_B = nameplate rating, and $\cos\Theta$ = power factor. For this report, η is shown for $\cos\Theta = 1$. Since voltage fluctuation under operating conditions is limited, the voltage assumption is acceptable for well-designed distribution transformers.

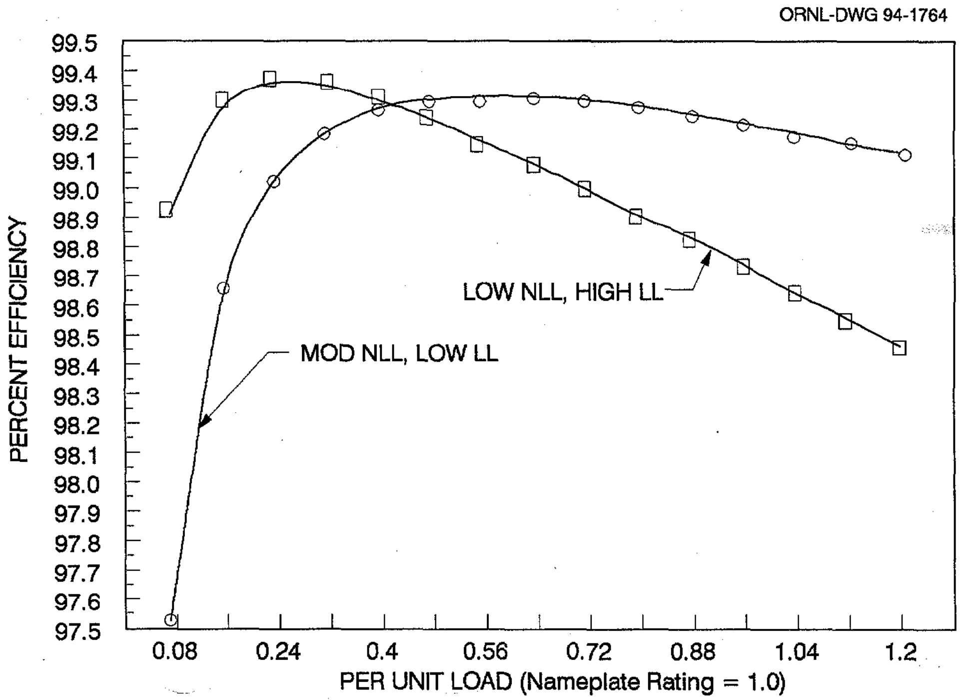

Fig. 3.4. Typical transformer efficiency vs per unit load relative to nameplate rating. NLL = no-load losses; LL = load losses.

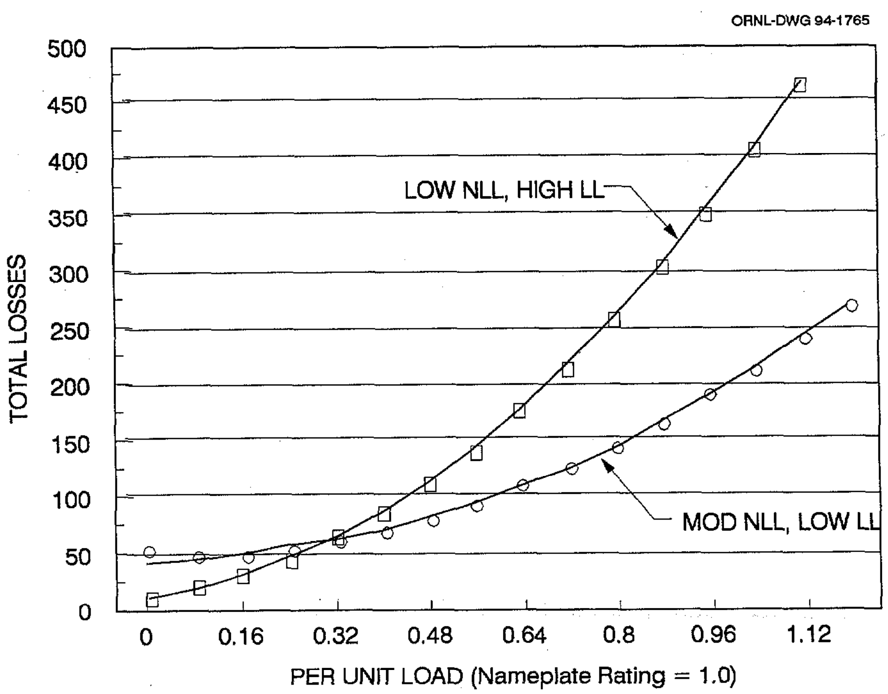

Fig. 3.5. Typical total losses as functions of load, indicating trade-off of relative load and no-load losses. NLL = no-load losses; LL = load losses.

better size the transformer to the load characteristics.[9] Studies seem to indicate that distribution transformers are lightly loaded most of the time, with short periods of time in which loads may be 50–100 percent above the rated load. In other words, a 10-kVA transformer might be loaded at 15–20 kVA for periods of a few hours per year with slight loss in useful life.[10,11]

An important point to note is the relatively large spread in the peak load. Nickel[10,11] suggests a variable peak loading with an initial peak load of 0.6 to 1.0 and a final peak of 1.25 to 2.0 based upon a 1971 industry survey. The present study uses an initial peak of 0.8 and a final peak of 1.5. The transformer load is assumed to grow from the initial to the final peak at a specified rate, at which point the transformer is moved to a lower load location or retired. Using a generally accepted formula relating loss factor to load factor [$LSF = (0.15 + 0.85LF)LF$] and a load factor of 0.32 implies a loss factor of 0.135, which is used in both this study and the earlier work of Nickel.[10] Since these data are utility-specific, the use of a single national average figure presents some risk. Even within a utility this information is constantly changing and is often evaluated by indirect methods. However, this data is representative.

A subject of major concern to utilities is projected equipment life. For distribution transformers a loading guide has been established.[12] This guide provides a method for determining the insulation's hottest spot temperature as a function of load and a relationship between temperature and time that is used to compute transformer life. Present distribution transformers are designed to operate 20 years at the design load and specified hot-spot temperature. Underloaded transformers are clearly less stressed thermally and may have lives extending well beyond 30 years, but transformers loaded to greater than nameplate rating for extended times may have significantly shortened lifetimes. The national average age data referenced below implies that distribution transformers may be significantly underloaded.

Transformer loading guides define the life of the insulation material in terms of mechanical strength, which, in turn, is related to the chemical properties of the paper insulation material (i.e., the degree of polymerization). The degradation of the long chains of cellulose molecules effectively reduces the tensile and dielectric properties. While there is a correlation between the tensile strength of the paper in the oil/paper system and dielectric performance, such a measure of insulation life is not ideal. The insulation system, and hence transformer life, are also dependent upon dielectric stress (transient overvoltage such as lightning and switching surges), mechanical vibration, and thermal expansion and contraction. Transformer life is also influenced by other non-load-related failure mechanisms such as accidents, extreme weather conditions, and even administrative decisions to retire the units with insufficient remaining apparent service life following a changeout.

For this report, a national average for utility distribution transformer life of 31.95 years and a standard deviation of 6.4 years was used. It should be noted that 30 years is the typical period used for evaluating TOCs. The data and analytical process used to model the distribution of utility transformer life are contained in Appendix D. This model is especially useful for estimating the average life remaining on units in service. Such estimates can be used at changeout to determine whether to scrap or reuse the transformer.

While the present average age is well beyond the 20-year design life, there is evidence of attempts by some utilities to more closely match load to transformer size. This strategy may result in smaller transformers for a given customer site, more customers served by individual transformers, and potentially shorter transformer life due to the resulting higher loading factors. The overall result should be a reduction in TOC.

In making the decision to reduce transformer size, utilities must consider voltage regulation. Voltage drop in the transformer due to sudden load change can result in customer complaints. For example, an electric motor requires up to 6 times the operating current during startup, and if the motor is large in size relative to the transformer, voltage can be significantly reduced for up to 15 seconds until the motor reaches operating speed. A common solution to motor-caused voltage-drop problems is to oversize the transformer. The net result is an underloaded transformer with a relatively long life.

4. ECONOMIC ANALYSIS

The economics of upgrading distribution transformers during routine utility maintenance requires a life-cycle cost (LCC) comparison. The LCC of continuing to use an existing transformer is compared to the LCC of replacement with a new transformer. This comparison is referred to as "transformer replacement economics." This chapter discusses the method of comparison and the development of required assumptions, and then develops cases that demonstrate what conditions favor continued use of refurbished transformers or replacement with new transformers.

The LCC comparison in this section is simplified by focusing only on those aspects of the transformer's LCC that differ between refurbishing a transformer and early replacement with a new transformer. Therefore, some costs associated with owning and maintaining transformers that would not vary between refurbishment and replacement are not included in this comparison.

4.1 APPROACH

4.1.1 Economics of New Transformer Alternatives

Industry sources indicate that most utility purchases of new transformers are based on an evaluation of TOC,* which is calculated by adding the purchase price or first cost of the transformer to the estimated capitalized value of the transformer's energy losses. This valuation of a transformer's energy costs makes them directly comparable to its first cost. The loss formula indicates how a *specific* utility can estimate the capitalized value of no-load and load losses for new transformers over a study period.[7] For instance, typical values might be $3.00 per watt of no-load loss and $1.00 per watt of load loss for a 30-year study period. Therefore, a transformer with losses of 100 watts (no-load) and 280 watts (load) would have a capitalized value of losses for the entire study period of $300 (no-load) and $280 (load). The total capitalized value of the losses would be $580, and if it is assumed that the initial cost of a new transformer is $500, the TOC of the transformer over the 30-year study period would be $1080.

*The total owning cost (TOC) is a capitalized value, making the first cost of the transformer comparable to the lifetime energy costs. The life cycle costs (LCCs) reflect the discounted life time costs of the transformer, where capital costs reflect interest and depreciation plus other costs associated with the transformer's initial cost. The capitalized values can be converted to the equivalent discounted present values of LCC by multiplying by the ratio of the fixed charge rate over the capital recovery factor.

TOC is given by the following equation:

$$TOC = NLL \times A + LL \times B + C \ ,$$

where

TOC	=	total owning cost,
NLL	=	no-load loss in watts,
A	=	cost per watt of no-load loss (this is termed the A factor),
LL	=	load loss in watts at the transformer's rated load,
B	=	cost per watt of load loss (this is termed the B factor),
C	=	the initial cost of the transformer, including transportation, sales taxes, and other costs to prepare it for service.

The makeup of the A and B factors will be further discussed below. For now, these factors can be interpreted as summarizing a utility's economic costs associated with the per unit load and no-load losses on its distribution transformers.

Given the A and B factors, the TOC can be easily calculated for transformers with various combinations of losses and initial costs to determine the transformer that has the lowest TOC—i.e., is the most economical for a given utility application. If alternative transformers are considered similar in terms of other considerations such as reliability and expected service life, then the most economical transformer would be the one that had the lowest computed TOC. Distribution transformer manufacturers typically make bids based on designs that achieve the lowest TOC given the utility's submission for the loss evaluation formula (A and B factors). Because the costs of transformer materials and design can be traded off to obtain higher or lower energy losses, transformer designs with significantly different loss and price characteristics may be economically competitive based on their TOCs. In fact, a single transformer manufacturer can come up with several different combinations of losses and initial purchase prices for a specific size and type of transformer with very similar TOCs. The key factor in the design strategy of finding the transformer with the lowest TOC is the relative prices of material and labor inputs with respect to the loss formula that will determine the transformer's TOC.

The hypothetical examples in Table 4.1 demonstrate the nature of the trade-offs between purchase price, a utility's loss formula (A and B factors), and the TOC. The A and B factors can vary from one utility to another based on differences such as the cost of electricity. As seen in the hypothetical example, variations in the A and B factors can result in the selection of different transformers.

In general, transformer manufacturers will design more energy-efficient transformers when bidding on transformer contracts that specify higher A and B factors. However, as can be seen by these examples, energy efficiency tends to be achieved at higher material and labor

Table 4.1. Economic trade-offs for hypothetical transformer designs

Example 1: Cost per watt of no-load loss, $4; cost per watt of load loss, $1				
	Design 1	Design 2	Design 3	Design 4
No-load loss (watts)	100	80	50	120
Load loss (watts)	220	280	290	310
Initial cost	$490	$475	$580	$350
Cost of no-load losses	$400	$320	$200	$480
Cost of load losses	$220	$280	$290	$310
Total owning cost	$1110	$1075	$1070	$1140
Rank (most preferred is 1)	**3**	**2**	**1**	**4**

Example 2: Cost per watt of no-load loss,$2.50; cost per watt of load loss, $0.75				
	Design 1	Design 2	Design 3	Design 4
No-load loss (watts)	100	80	50	120
Load loss (watts)	220	280	290	310
Initial cost	$490	$475	$580	$350
Cost of no-load losses	$250	$200	$125	$300
Cost of load losses	$165	$210	$218	$233
Total owning cost	$905	$885	$923	$883
Rank	**3**	**2**	**4**	**1**

Example 3: Cost per watt of no-load loss, $2.80; cost per watt of load loss, $0.75				
	Design 1	Design 2	Design 3	Design 4
No-load loss (watts)	100	80	50	120
Load loss (watts)	220	280	290	310
Initial cost	$490	$475	$580	$350
Cost of no-load losses	$280	$224	$140	$336
Cost of load losses	$165	$210	$218	$233
Total owning cost	$935	$909	$938	$919
Rank	**3**	**1**	**4**	**2**

costs in the manufacture of the transformer. The terms of the trade-off between the initial purchase cost and the transformer losses are given by the A and B factors. Practical examples of this trade-off are the ability to reduce load losses (B factor) by using more copper in the transformer's windings or substituting copper for aluminum in the windings. This trade-off varies with the changing relative prices of copper, aluminum, labor, and capital. Similarly, core materials with lower losses but higher costs (such as high grades of silicon steel and amorphous metals) can be used to reduce no-load losses (the A factor). It should also be noted that there are design trade-offs and cost differences in trying to design transformers with both low no-load losses (A factor) and low-load losses (B factor).

4.1.2 Economics of Early Transformer Replacement

The economics of early transformer replacement considers the LCC of a new transformer as outlined above, compared to continuing to use an existing transformer. The present values for capital and energy in the LCC analysis can be calculated directly from the corresponding TOC (capitalized) values and are proportionate. Therefore, a comparison of transformer costs using present values or capitalized values will yield the same result in terms of the comparison, although the total cost of the alternative will vary depending on the method used. The LCC of a new transformer is straightforward, as described above. The standard approach for comparing this cost to the cost of continued use of an existing transformer is to assume a remaining life for the existing transformer (for instance, 10 years) and then to assume that it will be replaced by the same new transformer that is assumed for early replacement. The total LCCs for each alternative can be calculated as a present value. For purposes of this study, because only transformers that have already been taken out of service for maintenance are being considered for replacement, the costs of reinstalling the transformer at the beginning of the study period would be incurred for either a new transformer or a refurbished transformer and can be ignored. If this were not the case, the costs of transformer removal and installation would have to be included in the LCC analysis. Tables 4.2 and 4.3 indicate the present values in the form of levelized costs* of a hypothetical example. The first-year costs for the "replace now" option include the levelized capital and energy costs that continue throughout the entire study period. The "refurbish and replace later" option incurs the refurbishment costs plus the levelized energy costs of the refurbished transformer in the first year; the levelized energy costs for the refurbished transformer for years 2 through 10; the take-down and reinstallation costs plus the levelized capital and energy costs of the new transformer in year 11; and the levelized capital and energy costs in years 11 through year 30.

*Levelized costs are the constant annual costs that, when discounted, are equivalent to a present value. Levelization provides a way of comparing two or more streams of values that may fluctuate widely on an annual basis.

Table 4.2. Time profile of cost components for early transformer replacement vs refurbishment

Year	Option and costs: Refurbish and replace later	Option and costs: Replace now
1	Refurbishment costs plus levelized energy for refurbished transformer	Levelized energy and capital for new transformer
2–9	Levelized energy for refurbished transformer	Levelized energy and capital for new transformer
10	Take-down and reinstall costs plus levelized energy and capital for new transformer	Levelized energy and capital for new transformer
11–30	Levelized energy and capital for new transformer	Levelized energy and capital for new transformer

Table 4.3. Example of present value cost comparison for early transformer replacement vs refurbishment

Cost component	Option and costs: (1) Replace now	Option and costs: (2) Refurbish and replace later	Net costs of replacing now
Cost of changeout and refurbishment		$201	−$201
Costs of no-load loss	$212	$378	−$166
Costs of load loss	$673	$628	+ $45
Capital costs	$734	$373	+$361
Total	$1619	$1580	+ $39

The cost comparison can be broken down into three categories: capital costs, energy costs, and costs related to changeout and refurbishment. The primary advantage of the refurbish and replace later option is that it delays the purchase of a new transformer and therefore reduces the present value of capital costs. The replace now option avoids the cost of refurbishment and the extra costs of take-down and reinstalling in year 11. The balance of the trade-off is the difference in energy efficiency in years 1 through 10. In years 11 through 30 both transformers have the same rate of energy use. The difference in the value of the energy efficiency is weighted by the years of remaining life of the refurbished transformer because, as stated above, after the refurbished transformer is replaced, there is no difference in energy use through the remainder of the study period. *The assumed remaining life of the refurbished* *transformer is extremely important in this comparison.* A shorter life reduces the present value of capital cost savings and increases the present value of the take-down and reinstallation costs. A longer life has the opposite effect. This is also an extremely important assumption because it has a relatively significant effect on the outcome of the comparison and because of its uncertainty. Another assumption of importance is the discount rate that is used to weight the future costs. This weighting factor accounts for the time value of money, progressively reducing the importance of future costs in the calculation of a present value. A lower discount rate tends to favor the option of early transformer replacement because it gives more weight to the higher energy costs of continuing to use the refurbished but presumably less-energy-efficient transformer. Perhaps of greater importance, the future changeout and capital costs of replacing the refurbished transformer are counted more heavily using a lower discount rate. The Office of Management and Budget (OMB) requires using a 7 percent real discount rate for this type of analysis. The discount rate, the A and B factors, price and performance characteristics of new transformers, and other assumptions necessary for this analysis will be discussed in Appendix E.

The economics of early replacement should also account for a difference in the residual value of the refurbishment alternative versus the replace-now alternative at the end of the study period. At the end of the 30-year study period, the transformer of the replace-now alternative will be older than the transformer that replaced the refurbished transformer at the end of its remaining life. This study accounts for this unequal remaining life as an end-effects adjustment to capital costs. This adjustment is about 8 percent of the present value for a 50-kVA transformer comparison where the remaining life of the refurbished transformer is 10 years. The assumptions used in the economic analysis of early replacement of transformers are detailed in Appendix E.

4.2 CASES AND RESULTS

The cases selected for study involve transformers representing varying transformer no-load and load losses. The cost of losses reflects a national social perspective that is detailed in Appendix E in the development of assumptions used to calculate the A and B factors. The efficiency and cost of new transformers and refurbishment, take-down, and reinstallation costs for refurbished transformers have been assumed from the industry survey. Three cases were tested using the cost of losses (A and B factors) based on the national averages estimated in Appendix E. The primary case assumed the average losses and costs for each size and type of new transformer reported in the industry survey. A second case used the lowest reported no-load-loss transformer and its corresponding load loss and cost reported for each size and type of new transformer purchased in the survey. A third case used the lowest-load-loss transformer and corresponding no-load loss and cost for each size and type of new transformer reported in the survey. A final case tested the sensitivity of replacement economics substituting the average A and B factors that have been reported by utilities in the industry survey for the A and B factors that were developed for use from the national perspective in Appendix E. This case used the average new transformer losses and costs reported in the survey. In all cases, the average refurbishment, take-down, and reinstallation costs from the industry survey were assumed.

Table 4.4 summarizes the results of the economic analysis. The key variable is the age at which the distribution transformer can be replaced cost-effectively. This has been determined by finding the years of remaining life at which a refurbished transformer's LCCs equal the LCCs of replacing it with a new one. This can be defined as the break-even point for early replacement. If the remaining life of the transformer is greater than this, then early replacement is not cost-effective. Transformers that come in for routine maintenance with fewer years of remaining life than the break-even point can be replaced cost-effectively. The transformer's break-even age was determined from an assumed distribution of transformer life and the remaining life of the transformer at the break-even point. This provides an age criterion for choosing between refurbishment and retirement based on choosing the cost-effective alternative. It also establishes the vintage of the refurbished transformer, which is used to assume its no-load and load losses in the economic analysis. The kVA of cost-effective early replacement in Table 4.4 has been estimated using the break-even transformer age and the estimated fraction of refurbishments that are older than the break-even age. The derivation of this estimate is explained in Section 5.1. Table 4.5 reports the cost and loss assumptions along with the break-even points for remaining life and transformer age for early replacement with new transformers that have average costs and losses as reported in the survey of investor-owned utilities. This is defined as the primary case.

The break-even age for early replacement of transformers in the primary case—with average-loss new transformers—is about 24 years (approximately 11 years of remaining life). For the second case, lowest no-load-loss transformers, it goes down to 22 years (about 13.1 years of remaining life), and for the third case, lowest-load-loss transformers, 21 years (about 13.5 years of remaining life). Comparing these national cost-effective break-even time frames to the utility survey data on refurbishments reveals that utilities are using a sound rationale on refurbishments (i.e., the survey data indicates relatively little refurbishment takes place on transformers older than these break-even points). For the primary case, which utilizes average costs and losses reported in the survey of utilities, only 13 percent of the transformers being refurbished could be replaced cost-effectively. The case with the highest rate of cost-effective early replacement is for the low-load-loss transformers, where 22 percent of refurbished transformers should be replaced. The final case, representing the utility perspective, indicates that even fewer refurbished transformers can be cost-effectively replaced as the average break-even age increases to about 28 years. This is because the average A and B factors for utilities reflect a lower value on transformer losses and utilities place a higher value on capital relative to expenses. In a sense, this case tests whether utilities are being

Table 4.4. Break-even points for cost-effective refurbishment/replacement decisions

Case	Av. remaining life at break-even point	Av. age of transformer at break-even point[a]	Est. kVA of cost-effective early replacements
Primary case: national perspective—new transformers with average losses	11.3	24.2	2,351,000
Low no-load-loss case: national perspective—new transformers with lowest no-load losses	13.1	22.0	3,531,000
Low-load-loss case: national perspective—new transformers with lowest load losses	13.5	20.9	3,935,000
Utility case: average utility evaluation—new transformers with average losses	9.0	28.4	1,154,000

[a]The average age of transformer at breakeven can be added to the average remaining life at breakeven to get the expected life of that transformer if it is returned to service. The expected life of a transformer increases as it survives. Therefore, a transformer at 30 years of age that is still operating would be expected to exceed the average distribution transformer life of 32 years (see Appendix D).

cost-effective from their own perspective and we would not expect replacement to be economical. The cost-effective early replacements using the utility evaluation factors result in replacement of about 6.5 percent of total refurbished transformer capacity.

The low-loss cases were analyzed to determine the sensitivity of energy savings. For each respective case, the lowest no-load loss or load loss transformers from the survey were used as the replacement transformer. Therefore, these cases are not intended to represent typical purchases of new transformers as in the primary case where transformer losses and first cost were averaged across all reported purchases for each size and type transformer. As with the primary case, the "national perspective" A and B values were used to estimate the cost of losses in the economic analysis of the low-loss cases. However, the cost of the transformers and the associated losses for the low-loss cases were taken from the specific transformer purchases reported in the survey with the lowest load losses and the specific transformer purchases with the lowest no-load losses. In Section 5.1, where energy savings for these cases are estimated, they provide some insight into the sensitivity of potential energy savings that might be attained from using these more efficient transformers as replacements. However, care should be taken in interpreting these results, because as stated above, the low no-load and load loss cases are based on utility-specific transformer purchases as opposed to averages.

Table 4.5. Assumptions for primary case: national perspective average-loss new transformers

Transformer type and size (kVA)		Av. Cost of new transformer	Av. no-load loss (watts)	Av. load loss (watts)	Av. cost to refurbish	Av. cost of exchange	Life remaining at break-even point	Age at break-even point
Pole type	10	$396	31	151	$130	$339	14	21
	15	$450	40	212	$137	$370	13	21
	25	$543	58	312	$168	$365	13	22
	37.5	$671	81	412	$168	$422	12	23
	50	$777	99	520	$220	$409	12	23
Pad type	50	$1,129	98	536	$309	$533	10	25
	75	$1,406	133	718	$309	$533	9	29
	167	$2,264	256	1,350	$314	$623	7	32
Three-phase	225	$4,892	396	1,998	$755	$926	10	25
	500	$7,197	721	4,021	$1,346	$1,410	14	20
	1000	$11,503	1,230	7,246	$1,346	$1,410	10	25
Av. age							11.3	24.2

5. POTENTIAL ENERGY SAVINGS AND OTHER IMPACTS

5.1 POTENTIAL ENERGY SAVINGS

An estimate of energy savings was made for cost-effective replacement criteria based on transformer age. First, differences of the no-load and load losses assumed for the new transformer cases were subtracted from typical no-load and load losses assumed for transformers of the vintage indicated by the cost-effective replacement criteria. The historic losses for transformers were weighted by the fraction of refurbishments and their associated losses for all refurbished transformers as old as or older than the age criterion. The no-load-loss differences were added to the product of 0.135 times the difference in load losses times average peak load squared, 1.0885 (see Section 3.2). The 0.135 is the peak-load-loss factor that converts peak-load losses to average per unit losses (see Section 3.2). This reflects a transformer with a peak load beginning at about 0.8 per unit and increasing at a compound annual rate of 1.7 percent over a 30-year study period. The procedure for calculating this average was to calculate the mean square of the per unit peak load for each year over the 30-year period. The resulting savings for each type of transformer was divided by the corresponding transformer size and summed to provide a weighted estimate of average energy savings in watts per kilovolt-ampere of transformer replacement.

Next, we estimated the cumulative fraction of refurbishments by transformer size and type taking place before any given year using the data reported in the utility survey. For instance, among utilities reporting the age of refurbished transformers in the survey, about 0.35 percent of refurbishment (by kVA) was for 25-kVA transformers purchased before 1965. The cumulative fraction of refurbishments that could be cost-effectively replaced was determined by adding the corresponding fraction for each type and size of transformer. This fraction was multiplied by the fraction 0.01 (1.0 percent) that refurbishments represented in the total kilovolt-amperage reported in the industry survey. The product of this multiplication is the estimated fraction of the total in-service transformers (in kVA) that could be cost-effectively replaced. Finally, the estimate of total kilovolt-amperage of in-service transformers was multiplied by this fraction and then multiplied by the weighted average replacement transformer energy savings in watts per kilovolt-amperage described above.

The energy savings for transformers meeting the cost-effective age criteria from the cases presented in Table 4.4 are estimated in Table 5.1. The primary case assumes that the energy value for transformer losses reflects a national perspective as developed in Appendix E. The national perspective indicates that for new transformers with average losses, only about 13 percent of refurbished transformers could be cost-effectively replaced with new transformers. The cost-effective replacement of refurbished transformers with average-loss

Table 5.1. Alternative cases of cost-effective early transformer replacement: energy savings estimates

Case	First year rate of saving per kVA	First year cost-effective refurbishments as percent of total refurbishments	Est. first year kVA of cost-effective early replacements	Billion kWh of savings in first year	Billion kWh of average annual savings for 25 years
Primary case	2.4	13.2 percent	2,350,000	0.05	0.14
Low no-load-loss case	3.7	19.9 percent	3,531,000	0.11	0.38
Low-load-loss case	2.3	22.1 percent	3,935,000	0.08	0.22
Primary case with upper bound historic losses	2.9	18.2 percent	3,239,000	0.08	0.23
Utility evaluation case	2.4	6.5 percent	1,154,000	0.02	0.07

new transformers would result in 0.05 billion kWh of savings in the first year. The lowest no-load-loss and load-loss cases result in 0.11 billion kWh and 0.08 billion kWh of savings in the first year, respectively.

The cases have been based on finding the most cost-effective replacement age for each type of transformer. If the analysis had imposed a single replacement age, energy savings could be higher or lower, depending on the age selected. However, there would be a tendancy, on average, for replacements to be less cost-effective.

Besides the primary case, low-loss cases, and the utility perspective, Table 5.1 also includes the primary case with an upper bound on historic losses. This recognizes the uncertainty in the assumed transformer losses of existing transformers. A General Electric study by Ward and Wong estimated the average losses for 10-kVA through 50-kVA single-phase transformers using a sample of transformers.[13] Ward and Wong also estimated that for 25-kVA transformers, 90 percent of the time the true average-loss values for the total population of transformers would be within $\pm$10–13 watts for no-load losses and $\pm$15–21 watts for load losses of the sample mean. The current study used these estimates to evaluate the primary case with an upper bound on historic losses. We adjusted all historic transformer loss estimates used in the analysis upward by the percentage corresponding to the percentages represented from the Ward and Wong estimates for 25-kVA transformers. Statistically, this upward adjustment indicates that we can be 95 percent confident that average historic losses were not greater than our assumptions. The remaining assumptions were identical with the primary case. The upward adjustment in historic transformer losses increased the energy savings by 76 percent over the primary case.

The last column in Table 5.1 indicates the estimated average savings if early replacement was practiced for 20 years starting in 1995. The average savings is significantly greater than for the first year. This is because each year a new batch of transformers would be replaced. Thus, the *annual rate* of energy savings would tend to accumulate as additional lower efficiency transformers were replaced with transformers of higher efficiency. However, each batch of replacements would tend to contribute progressively less energy savings after the first year. This is because the savings from replacement transformers are measured against the batch of transformers that are taken from service. If these transformers were refurbished instead, they would then gradually reach the end of their service life and be replaced with new transformers that would tend to be the same energy efficiency as the early replacement transformers. This would tend, over time, to reduce the difference in energy efficiency attributed to the batch of early replacement transformers. The difference would eventually become zero as all older transformers would eventually be replaced. Also, each succeeding batch of replacement transformers contributes somewhat less to the annual rate of savings as it replaces a progressively more efficient vintage of transformers. For instance, to replace a 20-year-old transformer in 1995, the savings are calculated based on the difference between the average losses of a new transformer and a 1975 vintage transformer. In 2005, replacing a 20-year-old transformer would mean replacing a 1985 vintage transformer that is more energy efficient than a 1975 vintage transformer. This result assumes energy efficiency for new transformers is not increasing in the future, therefore future transformer replacements result in progressively lower energy savings as they replace more recent vintages of transformers that are progressively more energy efficient. Ultimately, there are no energy savings attributed to early replacement because transformers are being replaced with transformers of identical efficiencies. Figure 5.1 portrays the pattern of annual energy savings for the primary case over time. The annual rate of savings would tend to rapidly rise over the first 10 years of the policy to about 0.2 billion kWh, 4 times its starting value, then rapidly fall. At 20 years, the annual rate would be less than in the first year and would continue to fall.

Figure 5.2 graphically portrays the average annual energy savings over a 25-year period starting in 1995 for three of the cost-effective early replacement cases. The savings in the primary case represent the equivalent of about 50 percent of a small power plant (a 50-MW plant at a 65 percent capacity factor) or the residential electricity requirements of a city of 40,000 people. The above cases indicate that energy savings of cost-effective early replacement are significantly increased over the average case by replacement with more efficient transformers.

5.2 IMPACTS ON UTILITIES

The effect on utilities of early replacement of transformers would depend on the criteria or rules used. The effect would depend on the additional capital cost the utility incurred for

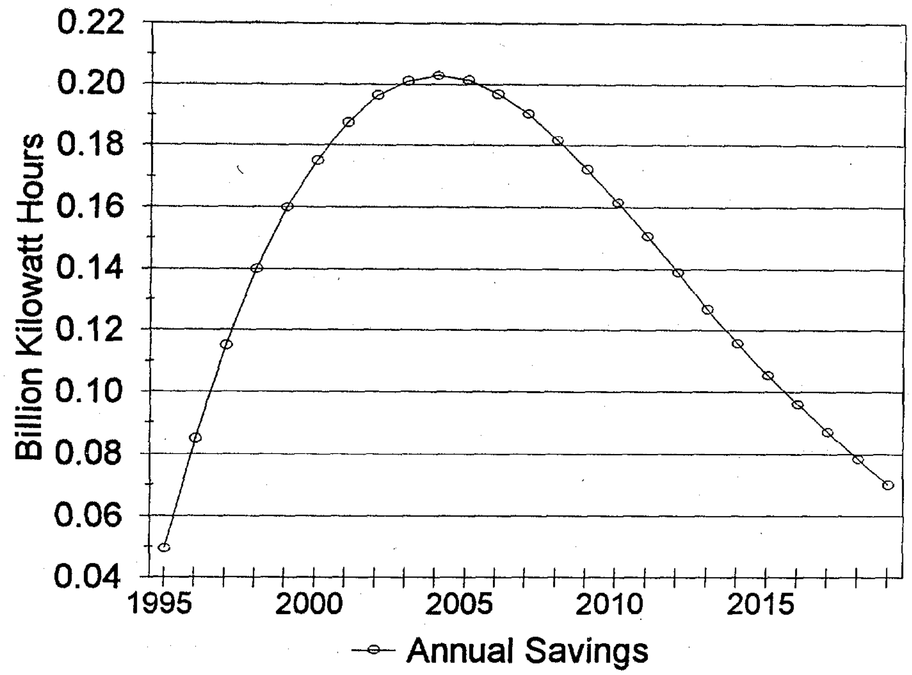

Fig. 5.1. Annual energy savings for the primary case, early transformer replacement.

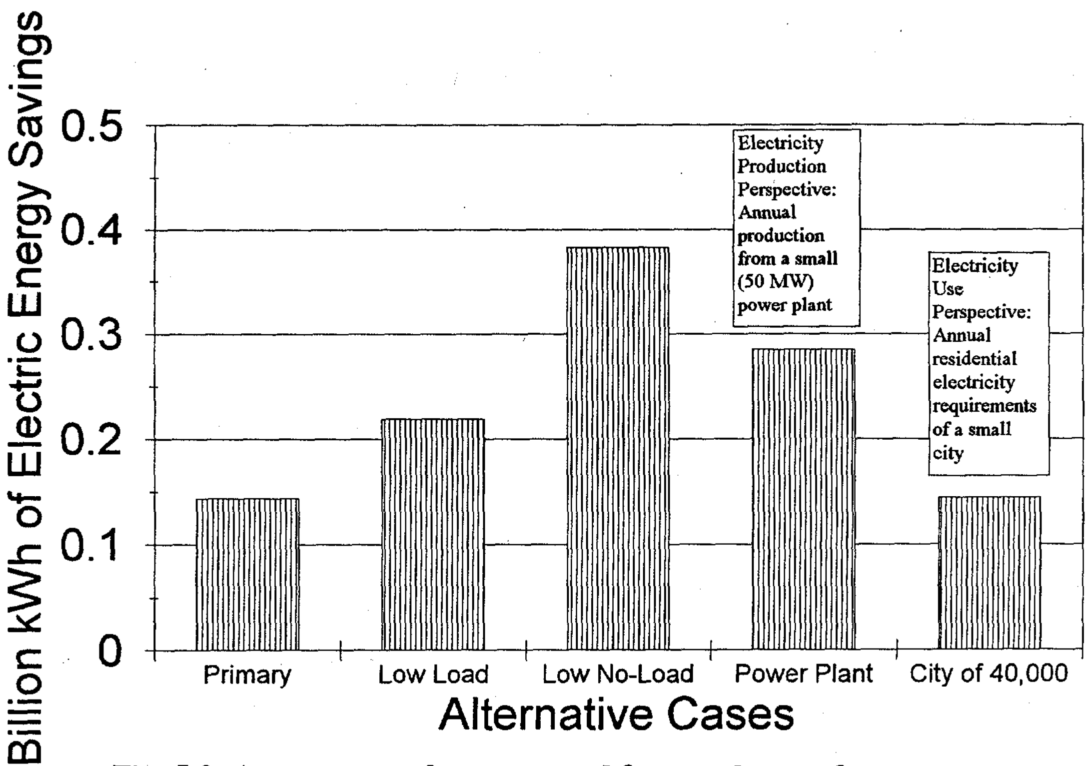

Fig. 5.2. Average annual energy saved from early transformer replacement cases with alternative perspectives.

early replacement and how much of this cost could be recovered by the utility through its electric rates. The average age criteria presented in Section 4, based on cost-effective early replacement, would tend to have a relatively small effect in increasing capital costs for new transformers. In the primary case, only about 13.2 percent of refurbishments would be affected by the cost-effectiveness criterion. For most utilities this would represent a small increase in new transformer purchases. For instance, the average rate of refurbishment (by kVA) is only about 24 percent of utilities' new transformer purchases. And 13.2 percent of this would be 3.2 percent.

Early replacement of transformers would tend to slightly reduce the average life of a utility's in-service transformers. At the same time it would tend to slightly increase total capital costs for purchasing transformers. The energy savings from early transformer replacement would reduce a utility's operating costs, but this cost savings would tend to be passed through to customers. The slightly increased capital cost for purchasing more new transformers would be absorbed by the utility until it could be incorporated into the rate base. The amount of time this required would depend on the utility's schedule for rate hearings. Therefore, before the additional capital costs could be incorporated into the rate base, the effect on utilities would tend to be slightly negative, since they would not be able to recover the carrying charge on the increased capital investment resulting from early replacement. In the long run, however, there would be little if any effect because utilities would eventually be able to adjust their rate base to include the increased capital costs. The foregoing assessment assumes that utilities would have no additional regulatory burden in complying with early replacement requirements.

5.3 IMPACTS ON MANUFACTURERS

The distribution transformer manufacturing industry is presently in a state of over-capacity, and most transformer manufacturers are currently producing at 60 to 70 percent of their capacity. Eight manufacturers produce roughly 80 percent of the distribution transformers in the United States. The annual distribution transformer sales to utilities is about 1.2 million units; however, survey data indicate that there can be significant annual fluctuations.

A survey of utilities (see Section 4) has indicated that 1.0 percent of the in-service capacity of transformers was refurbished in 1993. This amounts to approximately 372,000 refurbished in 1995 if one assumes that the sample is accurate over the entire population of transformers and that the average refurbished unit capacity was 47.7 kVA [1,778,635,000 (kVA of total capacity) $\times$ 0.01/47.7 = 372,879]. Based on a national perspective analysis, about 13 percent of the refurbished capacity could be economically retired. This would add only 48,000 transformers to the utility market, about 4 percent of the current utility distribution transformer market of 1.2 million units annually. Even if the total number of transformers now being refurbished on an annual basis were instead being replaced, the annual production of distribution transformers would be 1.50 million. The estimated full-capacity production of transformers is around 1.85 million units annually (1,200,000/0.65 = 1,846,154). The hypothetical increased production of distribution transformers to 1.50 million units is approximately 81 percent of estimated full-production capacity.

5.4 PRACTICABILITY ISSUES

The cost-effective replacement or upgrading of distribution transformers can be accomplished within the framework of existing utility practices. Many utilities are currently replacing or upgrading transformers in cost-effective strategies tailored to those utilities. This most often involves age criteria for transformer retirements or loss criteria where losses are determined from records or loss measurements. Some utilities may prefer to use a cost-effective loss criterion for retiring older transformers. This approach, however, requires that the losses for older units be known. If all utilities adopted cost-effective accelerated retirement policies based on the national perspective, the additional demand for distribution transformers would be only 4 percent of the new units now being purchased. Transformer manufacturers could easily meet this small additional demand.

5.5 CLIMATE CHANGE ACTION PLAN

The energy savings from the early replacement of transformers would result in a slight reduction of carbon emissions as power plants are operated less. DOE's estimate of carbon emissions by utilities for the year 2000 was divided by the projection of electricity produced by utilities.[14] This gives a rate of carbon emissions per kilowatt-hour. This rate can be applied to the electricity savings estimated in Section 5.1. Using this approach, we find that the cumulative reduction of carbon emissions by the year 2000 (1995–99) for the primary case for cost-effective replacement, as described in Section 4, would be 0.094 million metric tons (MMT). The average annual rate from 1995 through 2019 would be 0.025 MMT.

6. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

6.1 UTILITY DISTRIBUTION TRANSFORMERS

Electric utilities purchase about one million distribution transformers annually. The capacity of transformers for new installations is somewhat more than one-half of all new transformer purchases. Most electric utilities tend to purchase new transformers that provide the lowest TOC for their system. Loss evaluation factors associated with no-load core losses and full-load winding losses are developed using the utility's cost of energy and other economic parameters. The loss evaluation factors are provided to the transformer manufacturers to work up a bid for the utility to consider in purchasing new transformers.

The distribution transformer maintenance program used by most utilities involves inspection and testing, minor refurbishments, major refurbishments in the form of rewinding transformers, and retirements. Distribution transformers are removed from service for a variety of reasons, such as transformer overload, failure due to lightning or traffic accident damage, street or highway construction, or voltage upgrades. The removed units are delivered to the utility's transformer maintenance department, where they are examined to determine whether they should be refurbished and returned to stock or retired to scrap. Refurbishments range from minor in-house activities to major maintenance such as rewinding the transformer. Rewindings, however, are a very small part of the overall refurbishment activities, less than 2 percent of refurbished transformer capacity according to an industry survey.

6.2 POTENTIAL FOR COST-EFFECTIVE ENERGY SAVINGS

Survey data indicate that many utilities are currently replacing or upgrading transformers in cost-effective strategies tailored to those utilities. This most often involves an age criterion for transformer retirements or a loss criterion whereby losses are determined from records or loss measurements. If all utilities adopted cost-effective, accelerated retirement policies based on the national perspective, about 13 percent of the transformers currently being refurbished would be replaced by new units. The additional demand for distribution transformers would be only about 4 percent of the new units now being purchased. Transformer manufacturers could easily meet this small additional demand.

If all utilities adopted cost-effective, accelerated retirement policies based on the national perspective, 0.55 billion kWh of cumulative energy would be saved over the first five years, and the annual savings would average 0.14 billion kWh over the first 25 years. This amount of energy is equivalent to the residential electricity requirements of a small city of 40,000. The cumulative reduction of carbon emissions by the year 2000 would be 0.094 MMT. If very-low-loss replacement transformers are used instead of the average losses for new transformers, the average annual energy savings could increase to approximately 0.38 billion kWh.

6.3 CONCLUSIONS

Judging from the survey data obtained from utilities and the analyses contained in this report, on average electric utilities are making reasonable decisions regarding the replacement or refurbishment of distribution transformers that are removed from service. The comparison of the replacement practices by utilities in the survey and other national analyses contained in this report indicates a difference of only 13 percent in the number of refurbished transformers that could be economically replaced.

6.4 RECOMMENDATIONS

This survey of utilities provided information only for a selected group of utilities. The information and the analyses contained in this report reveal that the utilities surveyed are on average making reasonable assessments regarding replacement or refurbishment of distribution transformers. This does not mean that all utilities are making optimum economic assessments based on factors that are relevant to their operations. As discussed in Appendix E, there is considerable variation among utilities in key factors for these decisions. Therefore, individual utilities should perform similar economic analyses using factors that are relevant to their operations. To ensure that all utilities are aware of the economics of these assessments, it is recommended that DOE provide this report to the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association and work with those associations in informing their member utilities of the economics of refurbishment versus replacement of distribution transformers when they are removed from service. It is also recommended that this report be provided to the Environmental Protection Agency to assist in the implementation of its Energy Star Transformer Program, which is part of the President's Climate Change Action Plan. Under this program, participating utilities will agree to purchase high-efficiency distribution transformers where economically warranted and will institute the early replacement of distribution transformers where economically warranted.

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APPENDIX A

DISTRIBUTION TRANSFORMER SURVEYS

APPENDIX A

Distribution Transformer Surveys

In cooperation with Oak Ridge National Laboratory (ORNL), the Edison Electric Institute (EEI) and the American Public Power Association (APPA) sent out surveys to their member utilities requesting information about distribution transformers. The EEI association is composed of investor-owned electric utilities and includes most of the large utilities. The APPA consists of publicly owned municipal utilities. While these public utilities vary in size from very small to very large, their average size is much less than that of the investor-owned utilities. The National Rural Electric Cooperative Association was contacted but declined to survey its members for the purposes of this study.

The forms that follow were sent by EEI and APPA, respectively, to their member utilities. The forms are similar but have slight differences reflecting the preference for anonymity by some of the investor-owned utilities.

A preliminary survey form requesting information on transformers and utility maintenance practices was sent by ORNL to eight utilities.

The survey results presented are from the investor-owned electric utility survey only.

DISTRIBUTION TRANSFORMER SURVEY FOR ELECTRIC UTILITIES

INVESTOR-OWNED UTILITIES
DISTRIBUTION TRANSFORMERS: RETIRED, REFURBISHED, AND REWOUND TRANSFORMERS

THE DEFINITION OF REFURBISHED TRANSFORMER FOR THIS SURVEY IS ANY TRANSFORMER THAT IS TAKEN OFF LINE WITH THE INTENT TO REINSTALL WHETHER OR NOT ANY REFURBISHMENT OR MAINTENANCE IS REQUIRED, OR ANY COST IS INCURRED. HOWEVER TRANSFORMERS THAT ARE REWOUND ARE BROKEN OUT SEPERATELY.

TOTAL MVA OF ALL DISTRIBUTION TRANSFORMERS ON SYSTEM ________

PLEASE SPECIFY PREDOMINANT PRIMARY VOLTAGE CLASS i.e. 15 kV, etc. ________

Do you retire (scrap) old transformers that have been removed from service for reasons other than failure based on an age criteria ? ________

If so, how old ? ________

For 1993 or LATEST YEAR DATA IS AVAILABLE please provide following information on distribution transformers. Year of Data ? ________

Is following data from actual records or estimated? ________

Transformer Size (KVA) and Type	SYSTEM	RETIRED	REFUBISHED			REWINDS		Total KVA of REFURBISHED transformers by period in which they were purchased			
	Total KVA In-Service	Total KVA Retired	Total KVA Refurbished	Ave. Cost per Trx. to Refurbish	Ave. Cost to Remove & Reinstall	Total KVA Rewind	Ave. Cost per Trx. to Rewind	Before 1965	1965-1974	1975-1984	After 1984
SINGLE PHASE											
POLE											
0 TO 9											
10											
15											
25											
37.5											
50											
Above 50											
Pad											
0 to 100											
Above 100											
THREE-PHASE											
0 to 300											
Above 300											

EVALUATION FORMULA FOR PURCHASE OF NEW TRANSFORMERS

No Load Loss ($ per watt) ________
(A Factor)

Load Loss ($ per watt) ________
(B Factor)

LOADING PRACTICE

	25 KVA	37.5 KVA
Initial Peak Load on Transformer (per unit)		
Changeout Peak Load on Transformer (per unit		
Average Load Factor		

DISTRIBUTION TRANSFORMER SURVEY FOR ELECTRIC UTILITIES

INVESTOR-OWNED UTILITIES

PLEASE PROVIDE FOLLOWING INFORMATION FOR TRANSFORMERS OF INDICATED SIZE

COST AND EFFICIENCY CHARACTERISTICS OF NEW TRANSFORMER PURCHASES
(Most recent purchase for each category for predominant primary voltage class)

	Size (KVA)	Specify Primary Voltage Class	Year Purchased	Average Cost of New Transformer Including Transport & Sales Tax (Dollars)	No Load Loss (Watts)	Load Loss (Watts)	
SINGLE PHASE Pole	10						10
	15						15
	25						25
	37.5						37.5
	50						50
Pad	50						50
	75						75
	167						167
THREE PHASE Pad	225						225
	500						500
	1000						1000

DISTRIBUTION TRANSFORMER SURVEY FOR ELECTRIC UTILITIES

MUNICIPAL UTILITIES

UTILITY: ____________
RESIDENTIAL CUST.________
COMMERCIAL CUST. ________
INDUSTRIAL CUST. ________

IF DISCLOSURE OF INFORMATION ON THIS TRANSFORMER SURVEY IS SENSITIVE LEAVE BLANK AND NOTE "DISCLOSURE"

THE DEFINITION OF REFURBISHED TRANSFORMER FOR THIS SURVEY IS ANY TRANSFORMER THAT IS TAKEN OFF LINE WITH THE INTENT TO REINSTALL WHETHER OR NOT ANY REFURBISHMENT OR MAINTENANCE IS REQUIRED, OR ANY COST IS INCURRED. HOWEVER TRANSFORMERS THAT ARE REWOUND ARE BROKEN OUT SEPERATELY.

TOTAL MVA OF ALL DISTRIBUTION TRANSFORMERS ON SYSTEM ______

PLEASE SPECIFY PREDOMINANT PRIMARY VOLTAGE CLASS i.e. 15 kV, etc. _____

Do you retire (scrap) old transformers that have been removed from service for reasons other than failure based on an age criteria ? ______

If so, how old ? _____ WHAT IS THE AVERAGE SERVICE LIFE OR DEPRECIATION RATE FOR YOUR DISTRIBUTION TRANSFORMERS? ________

WHAT IS THE AVERAGE TIME THAT A DISTRIBUTION TRANSFORMER REMAINS ON THE SYSTEM IN ONE LOCATION? ________

**NOTE FOR THE FOLLOWING TABLE: ESTIMATES ARE ACCEPTABLE BUT PLEASE INDICATE WHERE DATA IS ESTIMATED.
IF TIME DOES NOT PERMIT FULL COMPLETION OF ALL CATEGORIES PLEASE FILL OUT AT LEAST FOR THE PREDOMINANT SIZE OF DISTRIBUTION TRANSFORMER ON YOUR SYSTEM**

For 1993 or LATEST YEAR DATA IS AVAILABLE please provide following information on distribution transformers. Year of Data ? ______
Is following data from actual records or estimated? __________

	SYSTEM	RETIRED	REFUBISHED			REWINDS		Total KVA of REFURBISHED transformers by period in which they were purchased				
Transformer Size (KVA) and Type	Total KVA In-Service	Total KVA Retired	Total KVA Refurbished	Ave. Cost per Trx. to Refurbish	Ave. Cost to Remove & Reinstall	Total KVA Rewind	Ave. Cost per Trx. to Rewind	Before 1965	1965-1974	1975-1984	After 1984	
SINGLE PHASE												
POLE												
0 TO 9												0 TO 9
10												10
15												15
25												25
37.5												37.5
50												50
Above 50												Above 50
Pad												
0 to 100												0 to 100
Above 100												Above 100
THREE-PHASE												
0 to 300												0 to 300

DISTRIBUTION TRANSFORMER SURVEY FOR ELECTRIC UTILITIES

MUNICIPAL UTILITIES

UTILITY: ___________________
RESIDENTIAL CUST.___________
COMMERCIAL CUST. ___________
INDUSTRIAL CUST. ___________

IF TIME DOES NOT PERMIT FULL COMPLETION OF ALL CATEGORIES PLEASE FILL OUT FOR THE PREDOMINANT SIZE OR SIZES OF DISTRIBUTION TRANSFORMER ON YOUR SYSTEM

PLEASE PROVIDE FOLLOWING INFORMATION FOR TRANSFORMERS OF INDICATED SIZE

COST AND EFFICIENCY CHARACTERISTICS OF NEW TRANSFORMER PURCHASES
(Most recent purchase for each category for predominant primary voltage class)

	Size (KVA)	*Specify* Primary Voltage Class	Year Purchased	Average Cost of New Transformer Including Transport & Sales Tax (Dollars)	No Load Loss (Watts)	Load Loss (Watts)	
SINGLE PHASE Pole	10						10
	15						15
	25						25
	37.5						37.5
	50						50
Pad	50						50
	75						75
	167						167
THREE PHASE Pad	225						225
	500						500
	1000						1000

DOES YOUR UTILITY USE AN EVALUATION FORMULA IN REQUESTING BIDS FOR NEW TRANSFORMERS? __________

IF SO INDICATE PLEASE INDICATE THE FOLLOWING:

No Load Loss ($ per watt) ________
(A Factor)
Load Loss ($ per watt) ________
(B Factor)

LOADING PRACTICE

	25 KVA	37.5 KVA
Initial Peak Load on Transformer (per unit)		
Changeout Peak Load on Transformer (per unit)		
Average Load Factor		

PRELIMINARY DISTRIBUTION TRANSFORMER SURVEY FOR ELECTRIC UTILITIES

1. Number of units removed from service, refurbished, and returned to service, and the total in-service distribution transformers (pole-top and pad-mount). Please fill in the table below:

Year	1993	1992	1991	1990
Total no. of in-service units				
Number removed from service				
Number of distribution transformers refurbished and returned to service				
Number disposed of (retired) for scrap				
No. of new distribution transformers purchased				
Total number of customers				

2. What tests do you perform to determine if a transformer can be returned to service?
   a) Insulation power factor test? (yes, no) ____________
   b) Oil tests? What type? ___________________
   c) Ratio tests? ________________________
   d) Other tests such as visual inspection, energizing? Specify: ______________

3. Retirement criteria
   a) Do you retire (scrap) old transformers that are in working order due to age?___
   b) If so, how old?_______.

4. Maintenance cost
   a) What is your averaged refurbishment cost?_______
   b) What is your averaged take-down and put back up cost?_______

5. Reasons for early retirement: system voltage change, PCB, etc.

RESULTS OF DISTRIBUTION SURVEY OF INVESTOR OWNED UTILITIES

TOTAL SYSTEMS' MVA	520,010
Total Reporting Utilities	63
% RETIREMENTS of In-Service	1.7%
% REFURBISHMENTS of In-Service	1.0%
Age beyond which do not refurbish (for utilities reporting a criterion)	25
UNWEIGHTED	
A Factor	$3.41
B Factor	$1.14
WEIGHTED (by respondent capacity)	
A Factor	$3.05
B Factor	$0.87

Distribtuion Transformer Loading

25 kVA	
Initial Peak	0.87
Final Peak	1.57
37.5 kVA	
Initial Peak	0.88
Final Peak	1.57

Transformer Size (KVA) and Type	Ave. Cost per Trx. to Refurbish	Ave. Cost to Remove & Reinstall
SINGLE PHASE		
POLE		
0 TO 9	$108	$342
10	$130	$339
15	$137	$370
25	$168	$365
37.5	$168	$422
50	$220	$409
Above 50	$334	$546
Pad		
0 to 100	$309	$533
Above 100	$314	$623
THREE-PHASE		
0 to 300	$755	$926
Above 300	$1,346	$1,410

RECENT PURCHASES OF NEW DISTRIBUTION TRANSFORMERS

Size (KVA)	RESPONSES	Average Cost Including Transport & Sales Tax (Dollars)	Average No Load Loss (Watts)	Average Load Loss (Watts)
SINGLE PHASE POLE				
10	38	$396	31	151
15	33	$450	40	212
25	54	$543	58	312
37.5	17	$671	81	412
50	52	$777	99	520
SINGLE PHASE PAD				
50	51	$1,129	98	536
75	36	$1,406	133	718
167	39	$2,264	256	1,350
THREE PHASE				
225	28	$4,892	396	1,998
500	50	$7,197	721	4,021
1000	45	$11,503	1,230	7,246

APPENDIX B

IN-SERVICE TRANSFORMER MODEL

APPENDIX B

In-Service Transformer Model

This appendix describes a methodology and presents estimates of energy savings that can result from the replacement of distribution transformers removed from service with new, low-loss transformers. Energy savings result because replacement units are more efficient than refurbished older units. The primary purpose of the in-service transformer model is to forecast estimated long-term energy losses from distribution transformer usage. The model also calculates estimates of new purchases and retirements both historically and in the future. The purchase and retirements estimates produced by the model are used only to develop an age distribution of transformers used in estimating total energy losses. They are not to be used as a substitute for annual estimates or data obtained by survey of new purchases and retirements.

Section B.1 describes the approach used in determining the potential energy savings. In this section, we describe an in-service transformer model that estimates the stock of distribution transformers over time as well its energy losses. Section B.2 presents the data and assumptions used in the application of the energy loss model described in B.1. Section B.3 presents a parametric analysis that gives the results of applying the in-service transformer model to various technology scenarios. Section B.4 presents a cost-benefit analysis of replacing the U.S. inventory of distribution transformers with low-loss units.

B.1 Methodology

A capital stock approach is used to model the in-service inventory of distribution transformers in the United States. The model is constructed so that the stock and energy consumption of the transformers can be calculated by vintage of transformer, annually and cumulatively over all years examined. The approach described here assumes an estimated or known initial stock of distribution transformers in service in the United States.

The general methodology for the development of a computer code to model the inventory and energy losses of distribution transformers requires an assumption of an initial stock of transformers and estimated energy losses per unit. Also, in an ideal model, data on annual additions to and retirements from the stock of transformers would be available. If annual retirements are not available, the use of a decay or retirement function is necessary. Energy loss values, unique to each year of transformer production, are multiplied by each vintage and summed over all years to estimate total energy losses.

The model assumes that data on annual additions to the transformer inventory are *not* available but that estimates of the total inventory of transformers are available on an annual basis. The estimation of additions to the stock is then determined by using the annual inventory and retirement levels. Since we do not have reliable data for transformer purchases or additions for the historical period of the model, this methodology is the approach we used to conduct our energy loss analysis.

The additions to the in-service transformer model have to be estimated by utilizing annual stock values and the vintage decay function.* The additions to stock for year 1 are estimated by subtracting from the initial stock for year 1 an estimate of the stock value in year $t-1$. This is represented in Eq. (B.7). The calculation of additions for years 2 through T is shown in Eq. (B.8). Additions for these years are calculated by subtracting from the stock in year T the decayed initial stock and the sum of previous additions multiplied by their decay function. (The decay, or scrappage, relationship is described in Section B.3.)

$$A^1 = S^1 - S^1 e^{-r1} = S^1 (1 - e^{-r1}) \tag{B.1}$$

$$A^T = S^T - S^1 e^{-r1T} - \sum_{t=1}^{T} A^t \times d(T-t) \quad , \tag{B.2}$$

where

A^1 = estimated addition for year 1,
S^1 = estimated stock for year 1,
$r1$ = retirement or scrappage rate for the original stock,
A^T = estimated addition for year T,
S^T = stock of transformers existing in service at year T,
A^t = annual addition of distribution transformers to the stock of existing transformers for year t,
$d(T-t)$ = a decay function representing the reduction of transformers from use at year t.

The decay function varies in value from 1.0 to 0 and is the percentage of transformers remaining in stock at year t. It is assumed that the decay relationship will have characteristics similar to a logistic or Weibull function with a half-life of approximately 20 years (the Weibull decay function is discussed in Appendix D). The component e^{-rT}, varies in value from 1.0 to near zero, where r is scrappage rate for the initial stock.

Refurbishments. The amount of the transformer inventory that is refurbished each year is based on survey information. This information, discussed in Section 5, indicates the

*It is important to note that the transformer stock and additions discussed here are given in terms of capacity (megavolt-amperage). The calculation for the number of transformers is shown in the next section.

percentage of stock that was refurbished during various time periods. Equation (B.3) gives the relationship for refurbishments:

$$R^T = S^1 e^{-r1} / N_{\mathrm{ri}} + A^{T-N\mathrm{rf}-1} d(N_{\mathrm{rf}}) \quad , \tag{B.3}$$

where

R^T = amount of transformer refurbishments in year T in MVA,

N_{rf} = number of years of transformer service before refurbishment,

N_{ri} = average number of years before refurbishment for annual components of the initial stock.

Calculation of numbers of transformers. The number of transformers in the U.S. stock (as well as the average size in kVA over time) is needed to calculate energy losses for transformers, since average load and no-load losses are given on a per transformer basis. Estimations of average size of transformer per vintage are given in kVA and are divided into the value for each year's additions in MVA. This gives an estimation of the number of transformers added to the stock each year. The analysis that provides these values is given in Section B.2.

Energy consumption of the transformer stock. The energy losses due to distribution transformers is a function of load and no-load losses. We assume that the losses per transformer are equal to the sum of the no-load loss plus the load loss times 0.135 (energy losses = no-load loss + load loss × 0.135), which requires that the average peak load over the life of the transformer be 1.0 per unit with a loss factor of 0.135.

The estimated energy consumption for the initial stock of transformers for year T is

$$QI^T = \mathrm{Trans}_{\mathrm{I}} \times e^{-s1(T-1)} \times (E_{\mathrm{NL}} + E_{\mathrm{LD}} \times 0.135) \quad , \tag{B.4}$$

where

QI^T = energy loss for the initial transformer stock due to operation in year T,

$\mathrm{Trans}_{\mathrm{I}}$ = initial stock of transformers at time period $T = 1$,

$s1$ = annual retirement rate of the initial stock of transformers,

E_{NL} = no-load loss per transformer in watts,

E_{LD} = load loss per transformer in watts.

For time periods greater than $T = 1$, the energy loss relationship shown in Eq. (B.5) is added to Eq. (B.4). In this relationship, the quantity of transformers purchased in year t and refurbished in year T are subtracted from the number of transformer additions for year t. The retirement function, $d(T - t)$, is multiplied by the number of net additions to produce the remaining additions in year T.

$$QA^{T} = \sum_{t=1}^{T} (ATN_t - RTN_t)\, d(T - t)\, (E_{NL} + E_{LD} \times 0.135) \quad , \qquad \textbf{(B.5)}$$

where

QA^T = energy loss for net additions to the stock at year T,
ATN_t = number of transformers added to the U.S. stock in year t,
RTN_t = number of transformers refurbished in the U.S. stock that were purchased in year t.

The total energy loss for the transformers that have been refurbished in year t is given by Eq. (B.6). The no-load and load losses presented here are particular to refurbished units and may be different from the losses of transformers purchased in the same time period.

$$QR^{T} = \sum_{t=1}^{T} RTN_t\, d(T - t)\, (ER_{NL} + ER_{LD} \times 0.135) \quad , \qquad \textbf{(B.6)}$$

where

QR^T = energy loss for refurbished transformers in year T,
ER_{NL} = no-load loss per refurbished transformer in watts,
ER_{LD} = load loss per refurbished transformer in watts.

The sum of the three relationships described by Eqs. (B.4), (B.5), and (B.6) gives the total energy loss for the U.S. stock of transformers at time T.

B.2 Data and Assumptions

This section discusses each major function of the transformer energy loss model along with specific data requirements. The source of the data is given, as well as the data values themselves. The five major functions of the energy loss model are

1. transformer stock,
2. retirement or scrappage and annual purchases,
3. refurbishment,
4. energy loss, and
5. energy savings.

B.2.1 Transformer Stock

The distribution transformers in the U.S. utility industry serve primarily the residential and commercial sectors and Rural Electrification Administration areas. DOE has summarized the information from the FERC Form One annual survey of approximately 200 electric utilities in the United States.[1] This form indicated approximately 30 million distribution transformers with a total of 1.29 million MVA in 1992. If this is proportional to these electric utilities' share of total sales to ultimate customers, there would be about 39.5 million transformers and 1.69 million MVA for all utilities.

The initial time period of analysis for the transformer energy loss model is 1961. Since there are no reliable data for transformer stock during the 1961–92 period, we utilize a proxy for these values. We assume that the growth of transformers is proportional to the annual peak load for the electric utility industry. We also assume that the average transformer size increases linearly from 27 to 43 kVA during the historical period of the model (1961–92). The average size of transformers purchased currently is approximately 58.6 kVA.

B.2.2 Retirement or Scrappage and Annual Purchases

The estimation of annual distribution transformer purchases or additions follows the methodology given in Section B.1.2. Actual data on annual purchases of distribution transformers is available from two sources:

1. FERC Form One data (1979–93) for approximately 200 major publicly owned electric utilities,[1] and
2. *Electrical World* annual T&D survey (1965–88).[4]

In general, the annual purchases calculated by the model are made up of two components: scrappage and new growth. That is, part of annual purchases must make up for the normal attrition of transformers removed from service. The other component of purchases accounts for the growth of the customer base and/or peak load of the system. This representation is shown by the graphic in Fig. B.1. Based on extrapolating data from FERC Form One, we assume that about 1.2 million transformers were purchased annually from 1989 through 1992.

The retirement or decay function for each vintage of transformer used in the model is represented by a Weibull function, with parameters given by Eq. (B.7) and shown in Fig. B.2.

$$DR_T = e^{(T/35)^4} \quad . \tag{B.7}$$

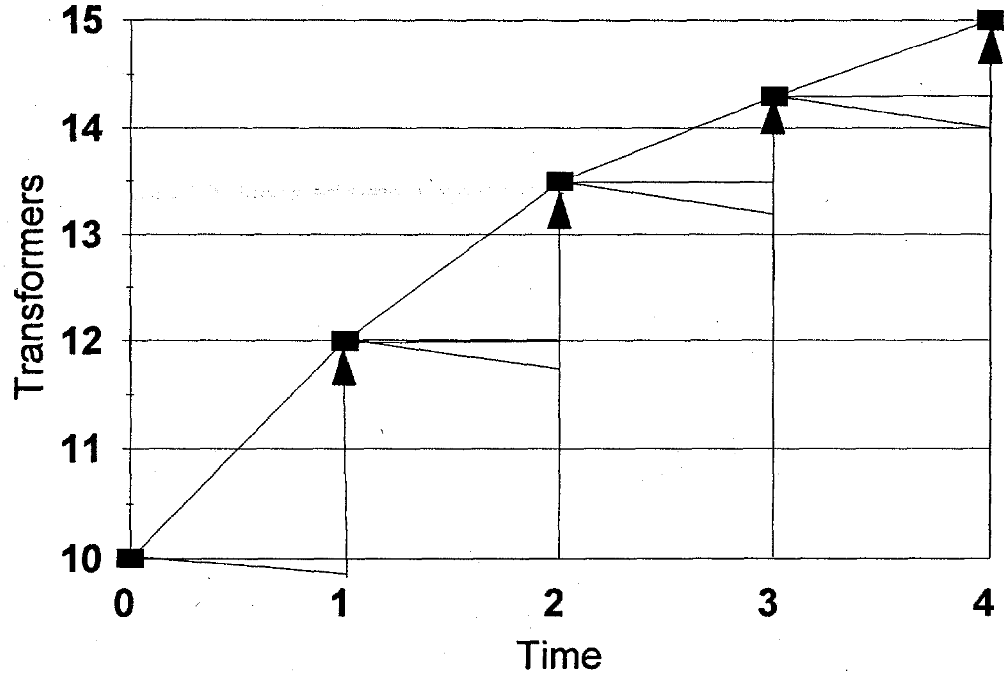

Fig. B.1. Estimation of additions to transformer inventory.

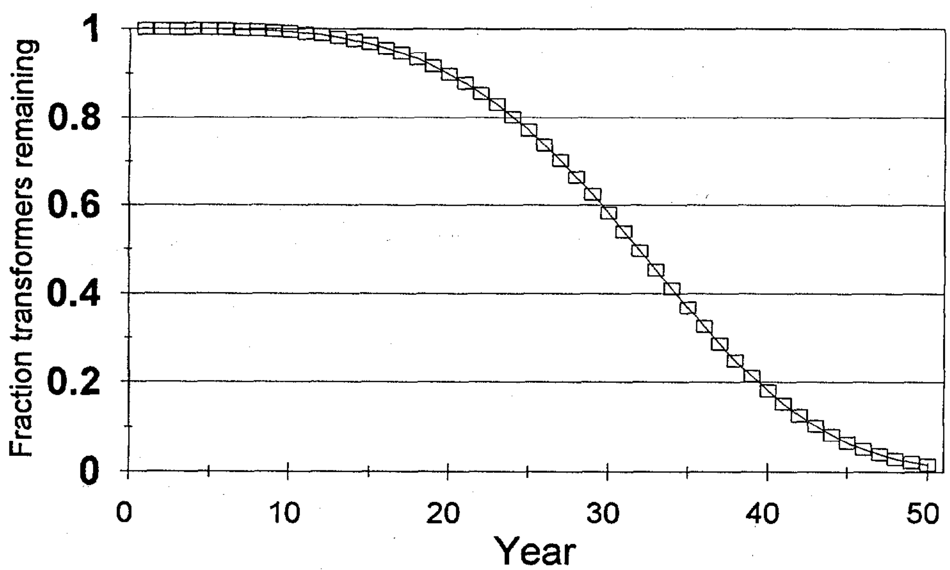

Fig. B.2. Retirement function, represented by Weibull distribution. (Parameters: $a = 35$, $b = 4$.)

This function provides the fraction of transformers in service after *T* years. We assume that the initial stock of transformers is retired at a rate of 3 percent per year. A tabulation of the fraction of transformers retired annually was calculated from 12 utilities that completed the FERC Form One from 1979 through 1992, an average of 1.6 percent during this time period. These values were similar to those produced by the energy loss model during the 1979–92 period. The trans-former stock, both in capacity and number (generated internally by the model), is shown in Table B.1.

B.2.3 Refurbishment

A survey was conducted by Edison Electric Institute (EEI) to determine, among other things, the fraction of distribution transformers refurbished from the in-service stock for 1992 by the utilities in the EEI membership. In addition, the age distribution of the fraction of transformers refurbished is also presented. The findings from the survey indicate that 1.0 percent of the in-service stock of transformers were refurbished during 1993. The age distribution of the transformers refurbished is discussed in detail in Section 2.4.

B.2.4 Energy Loss

The energy losses due to distribution transformers for electric utilities are made up of two components: no-load and load losses. These losses are discussed in detail in Section 3. In general, to calculate losses, the estimated number of distribution transformers calculated annually by the energy loss model is multiplied by the sum of the no-load loss and the load loss times the product of 0.135 times 1.0885 (energy losses = no-load loss + load loss $\times$ 0.135 $\times$ 1.0885). (For a discussion of the energy loss formulation, see Section 5.1.) Tables B.2 and B.3 give the no-load and load losses for the predominant range of distribution transformers in use by electric utilities from 1960 through 1985. The average size of distribution transformers in the United States from 1961 to the present increased from approximately 27 kVA to 43 kVA. We interpolate the energy loss values in Tables B.2 and B.3 over time and by size (kVA) to arrive at energy loss values used by our model. These values are shown in Table B.4. During the forecast period of 1993 to 2010, we assume that the average no-load and load losses are the same as those in 1992 and that the loss factor and average per unit peak do not change significantly.

Table B.1. Transformer stock capacity (MVA) and number of units: energy loss model baseline output

Year	Capacity	No. of units
1962	430,729	15,693,190
1965	491,216	16,662,730
1970	717,710	22,775,030
1975	1,026,008	30,585,000
1980	1,237,852	33,824,990
1985	1,371,506	35,504,680
1990	1,593,127	38,224,160
1995	1,778,635	41,659,010
2000	1,935,047	45,322,480
2005	2,105,214	49,308,120
2010	2,290,346	53,644,260

Table B.2. No-load losses for distribution transformers (watts)

	Transformer size (kVA)					
Year	**15**	**25**	**37.5**	**50**	**75**	**100**
1960	87	127	171	212	287	357
1965	81	118	159	197	267	331
1970	79	115	155	192	260	323
1975	71	103	139	172	233	289
1980	62	90	123	152	205	255
1985	54	78	107	131	177	221
1993	40	58	81	99	133	166

Table B.3. Load losses for distribution transformers (watts)

	Transformer size (kVA)					
Year	**15**	**25**	**37.5**	**50**	**75**	**100**
1960	234	343	465	578	783	972
1965	211	309	419	521	706	876
1970	191	279	378	470	637	790
1975	196	286	385	481	655	809
1980	200	293	393	492	672	827
1985	205	301	400	503	690	845
1993	212	312	412	520	718	875

Table B.4 Loss characteristics of distribution transformers utilized by energy loss model (watts)

Year	No-load losses	Load losses	Average size (kVA)
1961	134.2	361.0	25
1965	133.0	349.1	26
1970	137.5	334.6	29
1975	130.3	361.8	31
1980	121.5	390.4	33
1985	111.4	418.6	36
1990	92.5	435.0	38
1992	87.2	447.3	40

B.3 Energy Loss Simulations

The in-service transformer model was used to produce a baseline scenario to simulate distribution transformer energy losses from 1961 through 2010. The model assumes that the growth of national transformer stock is proportional to peak load growth. In addition, we assume that all annual purchases of transformers are subject to the retirement or scrappage relationship detailed earlier in this appendix. All other assumptions for the input parameters necessary to create a baseline simulation of the model are also presented in this appendix.

Figure B.3 shows our baseline simulation of U.S. transformer stock in megavolt-amperes from 1962 to 1992, and forecasts results to 2010. Figure B.4 shows the growth in the estimated number of transformers from 1962 through 2010. The growth rates in Figs. B.3 and B.4 do not match because the average transformer size (in kVA) has been increasing steadily during this period; this causes the growth rate in number of transformers to be lower than the growth rate in capacity.

Figure B.5 presents the estimated energy losses to the U.S. utility industry from distribution transformers from 1970 to 2010. The growth rate is relatively flat from the current time period to 2010. The reason is twofold: (1) the gradual replacement of less efficient transformers with more efficient ones, and (2) the reduction of growth rate of peak load during the forecast period with a resulting higher percentage of retirement of older vintages of transformers. Table B.5 summarizes the values presented in Figs. B.3, B.4, and B.5.

Three other model scenarios presented for comparison with the baseline case are shown in Table B.6. All but case C involve only the 1992 to 2010 period. In case A, one-fourth of the new purchases of transformers consist of low-loss units with no-load losses of 28.4 watts and load losses of 394 watts. In case B all of the new purchases of transformers consist of low-loss units. In case C, the entire national in-service stock of transformers was instantaneously replaced in 1992 with low-loss units.

Cases A and B show reductions in annual energy loss levels for national transformer use from 1992 to 2010. This is largely due to the replacement of older transformers having higher loss characteristics, with low-loss transformers. The loss forecast for case C shows an increase in losses over time since all the transformers in this hypothetical case have the same loss characteristics, and the in-service stock of transformers is increasing over time. Table B.7 compares the loss characteristics of the average transformer in service in the United States with low-loss units.

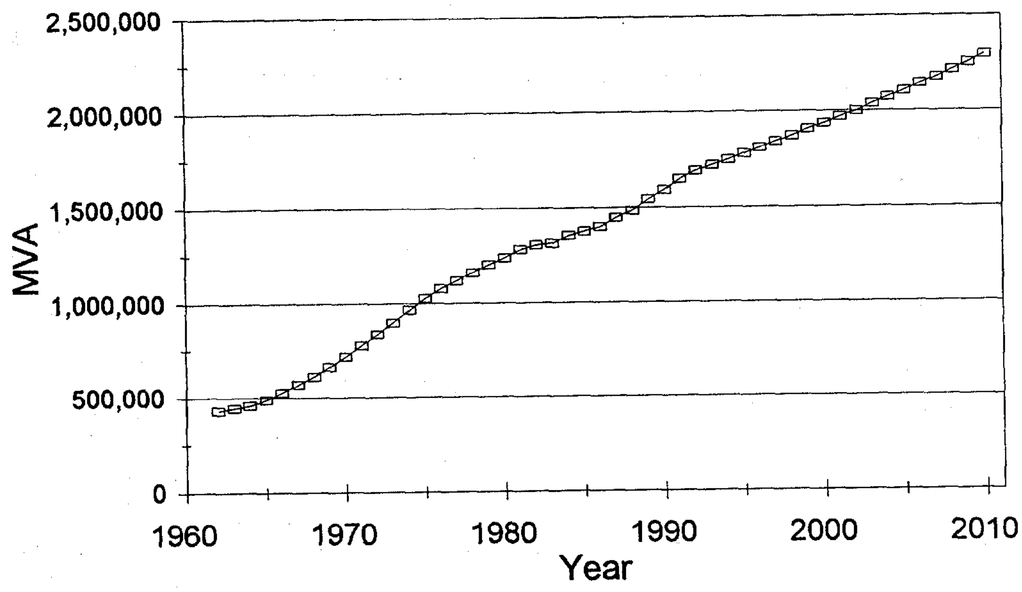

Fig. B.3. Baseline simulation of U.S. in-service transformer capacity.

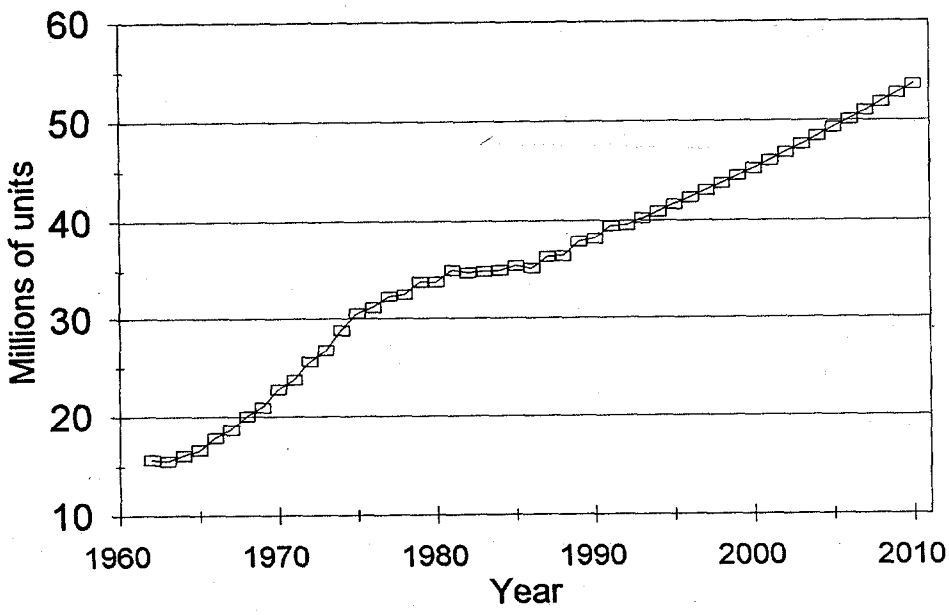

Fig. B.4. U.S. in-service transformer units.

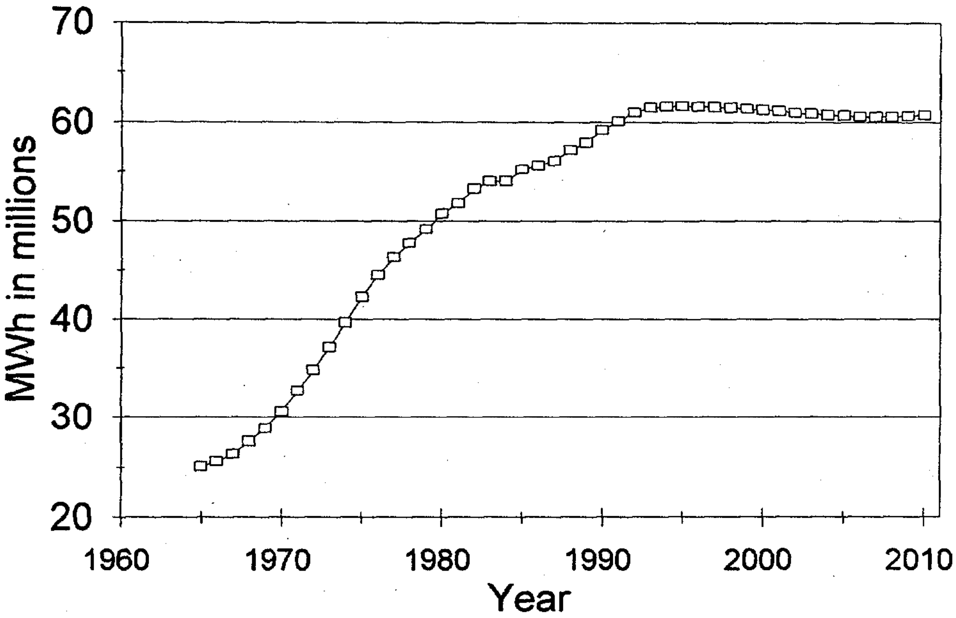

Fig. B.5. U.S. distribution transformer losses.

Table B.5. Baseline forecast of distribution transformer growth

Year	Capacity (MVA)	Number	Energy losses (millions kWhs)
1970	717,710	22,775,030	30,583
1980	1,237,852	33,824,990	50,759
1990	1,593,127	38,224,160	59,243
2000	1,935,047	45,322,480	61,257
2010	2,290,346	53,644,260	60,724
Growth rate, percent, 1970 - 1990	5.08	2.62	3.36
Growth rate, percent, 1990 - 2010	1.83	1.71	0.12

Table B.6. Comparison of baseline losses with cases A, B, and C
(Energy losses in million kWh/year)

Year	Baseline	Case A	Case B	Case C
1992	61,000	61,000	61,000	16,998
2000	61,257	60,015	56,314	17,866
2010	60,724	57,217	46,664	18,901

Table B.7. Comparison of losses between average vintage transformer and new very low-loss units
(watts)

Transformer class	No-load loss	Load loss
Av. transformer in service in U.S. (42.8 kVA)	151	423
1993 vintage	87	460
Low-loss transformer	28.4	394

B.4 Cost-Benefit Analysis of Inventory Replacement with Low-Loss Units

This section discusses a cost-benefit comparison of two options relating to distribution transformer use from 1992 to 2010. The two options consist of (1) the use of the existing U.S. stock of distribution transformers following the baseline scenario described in Table B.5, compared with (2) the instantaneous replacement in 1992 of the entire U.S. stock of distribution transformers with low-loss units. The cost-benefit analysis determines whether the energy savings due to the instantaneous replacement of the transformers is greater than the cost of changeout.

Table B.8 presents the results of this analysis. Line [1] gives the average energy savings for the changeout to low-loss transformers.* We assume the average transformer in stock in 1992 is approximately 42.8 kVA with no-load losses of 151 watts and load losses of

*We refer to the value given on each line as [*n*], i.e. the value given for line *n*.

Table B.8. Parameters for cost-benefit analysis of total replacement of U.S. stock of distribution transformers with low-loss units

[1]	Average kWh savings	4.4012×10^{10}
[2]	Average levelized production cost/kWh	0.03
[3]	Production cost savings	$1,320,366,493
[4]	Present-value factor for 30 years at 7 percent	12.41
[5]	Total present value of production cost savings	$16,384,482,189
[6]	Capacity savings in KW at 65 percent capacity factor based on average kWh savings	7,729,578
[7]	Capacity value per KW	$1,000
[8]	Capacity value	$7,729,577,877
[9]	Total capacity and production cost savings	$24,114,060,066 avoided cost
[10]	Approximate cost of transformer	$919
[11]	Total stock of transformers (units)	39,605,000
[12]	Transformer capital cost	$36,396,664,160
[13]	Average changeout cost	$422
[14]	Transformer changeout cost	$16,713,158,080
[15]	Less future reduction in transformer capital (derived by depreciation rate of 0.03 × transformer capital cost × periodic payment for 15 years at 0.07 discount rate)	$9,944,930,617
[16]	Average scrappage rate, 1992 to 2007	0.026
[17]	Credit for reduced changeout costs (scrap rate × 15-year present-value factor × average changeout cost)	$3,957,772,170
[18]	Total transformer costs for instantaneous changeout to low-loss transformer	$39,207,119,453

423 watts. The comparable loss values for replacement low-loss transformers is 28 watts for no-load and 394 for load losses. Line [3] is the estimated annual cost savings for one year of producing the quantity of energy saved ([3] = [1] × average levelized electricity production cost [2]). Line [5] is the present value of 30 years of the savings in [3] (at 7 percent discount rate).

The reduction in energy losses will result in avoiding constructing new generating capacity. The generating capacity saved [6] is calculated by converting kilowatt-hour savings [1] to kilowatts and dividing this value by the capacity factor (0.65). The value of this capacity savings is shown in line [8] ([6] × [7]). The total value of energy and generating capacity savings is given in line [9] ([5] + [8]). This is the avoided cost.

The following discussion consists of determining the cost of changeout to low-loss transformers: The total cost of installing new transformers is [14] ({cost/unit [10] + installation cost/unit [13]} × total units [11]). Subtracted from this value is the reduction in capital needed for future transformer purchases. This amount [15] is included because all older transformers in the U.S. stock are included in the changeout. In addition, the value reflecting the credit for reduced changeout costs [17] is added to the total cost of changeout.

The total cost for instantaneous changeout to low-loss transformers is given by [18]. This value is calculated by the following relationship: [18] = [12] + [14] − [15] − [17]. The total costs for instantaneous changeout to low-loss transformers [17] is greater than the avoided energy and capacity costs of a U.S. stock of these transformers. The costs for changeout are 1.6 times the value of avoided cost savings (1.6 = [18] / [9]). Using national average values, it is therefore not economically justifiable to consider such a changeout.

B.5 References

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3. Personal communication with John Gauthier, NEMA, February 1994.

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APPENDIX C

REWINDING TRANSFORMERS

APPENDIX C

Rewinding Transformers

Rewinding transformers is one approach some utilities use to increase a transformer's useful life. At the same time, rewinding a transformer may improve its load loss characteristics. The essence of rewinding is to take an existing transformer that has damaged windings or suffers from insulation stress and replace the windings and insulation. The core of the used transformer must be in good condition to make rewinding economically feasible. The transformer tank may also be reused if it is in good condition. At best, the no-load losses for a rewound transformer would remain the same because the core remains unchanged. The no-load losses could increase because of core handling and operational history. The load losses could be the same, lower, or higher depending on the quality of materials, workmanship, and revisions in design.

The key to the economic viability of a rewound transformer is the cost and remaining life of the rewound transformer compared to the cost and remaining life of a new transformer. In general, the cost of the rewind must be significantly less than the cost of a new transformer to be economically attractive. For 25-kVA transformers, the average rewinding cost reported in the industry survey was about 76 percent of the average cost for a new transformer. One utility reported that it would not pay more than 60 percent of the cost of a new transformer for a rewound transformer. For purposes of taxes and depreciation, the costs of rewound transformers at one major utility that practiced rewinds were capitalized, making them comparable to those of a new transformer. The alternative treatment would be to expense the costs of rewinds as is done for refurbishment costs. There are advantages and disadvantages to either treatment, revolving around how much of the cost can be recovered through inclusion in the utility's rate base if it is capitalized versus the opportunity to reduce tax liability by expensing the cost. Although for specific utilities, there may be some tax consequences associated with rewinding, in general this would not be a significant advantage or disadvantage.

Rewinds have not been included as part of early replacement assessment in this study for several reasons. First, a rewound transformer might be classified as either a new transformer or a refurbished transformer. Second, there is a lack of data and consequently much uncertainty about the performance of rewound transformers. The performance of rewound transformers can vary significantly, depending on the rewind manufacturer. Anecdotal evidence on rewound transformers suggests a wide variation from low quality to high quality. This could reflect quality differences among rewinders or some inherent problem with quality control. In addition to lack of information on a rewound transformer's remaining life, data on the energy characteristics of rewound transformers are not readily available. Energy differences between transformers before and after rewinding would probably not be significant because no-load losses would not be affected, as the transformer's core remains the same. Convergent with the lack of data on rewinds, the EEI/ORNL study indicated that rewinds constitute less than 2 percent of refurbished transformers. Therefore, even if major energy improvements resulted from rewinding transformers, the existing rates of rewinding would not result in significant energy savings.

APPENDIX D

RELIABILITY THEORY ESTIMATES OF DISTRIBUTION TRANSFORMER LIFE

APPENDIX D

Reliability Theory Estimates of Distribution Transformer Life

Given a probability density function $f(t)$ defining the probability of failure in the time interval t to $t + dt$, a reliability function $R(t)$ expressing the probability that the life of a given device (distribution transformer) exceeds time t can be defined; viz.,

$$R(t) = \int_t^\infty f(t)dt = 1 - \int_0^t f(t)\, dt \ . \tag{D.1}$$

Note that $R(t)$ expressed in the form of Eq. (1) implies that $f(t) = -dR(t)/dt$. A generally accepted expression for reliability is the Weibull distribution, which is given by

$$R(t) = \exp\left[-\left(\frac{t}{a}\right)^b\right] \ , \tag{D.2}$$

where the parameters a and b are used as fitting parameters for known reliability data, such as the mean and standard deviation of life for a specified group of devices. Note that the mean and standard deviation are expressed in terms of R as follows:

$$T = \int_0^\infty tf(t)dt = -\int_0^\infty t\frac{dR}{dt} \times dt = \int_0^\infty R(t)dt \tag{D.3}$$

and

$$S = \sqrt{\left[\int_0^\infty t^2 f(t)dt - T^2\right]} = \sqrt{\left[2\int_0^\infty tR(t)dt - T^2\right]} \ . \tag{D.4}$$

A national average* distribution transformer life of 31.95 years and a standard deviation of 6.4 can be used to provide values of $a = 31.63$ and $b = 4.15$. The reliability function $R(t)$ and the probability density function $f(t)$ are shown in Figs. D.1 and D.2.

A reliability of those devices which have lifetimes exceeding a specified time c can be expressed in terms of the population of devices still in operation at time c; viz.,

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*Clarence E. Mougin, "Depreciation Statistics from 100 Large United States Utilities—FERC Jurisdiction," *Journal of the Society of Depreciation Professionals* 4(1), 1992.

$$R_c(t) = \frac{R(t + c)}{R(c)} , \quad t + c \geq 0 . \tag{D.5}$$

The average life of the remaining population can be expressed in terms of this modified reliability function:

$$T_c = \int_0^\infty \frac{R(t + c)}{R(c)} \, dt = \frac{1}{R(c)} \left[T - \int_0^c R(t')dt' \right] . \tag{D.6}$$

Since the units that fail early are removed from the population, this average $T_c > T$ for all $t > 0$. Figure D.3 shows T_c as a function of c.

For the failure rate relative to the remaining population, the hazard function $Z(t)$ can be expressed as

$$Z(t) = \frac{f(t)}{R(t)} = \frac{-dR/dt}{R} . \tag{D.7}$$

The plot of this function is the classic "bathtub" curve. The cumulative or integrated $Z(t) = \ln[1/R(t)]$ is often used to visually indicate significant increases in failure rate (Fig. D.4). A significant cumulative failure rate is not seen until 40 years.

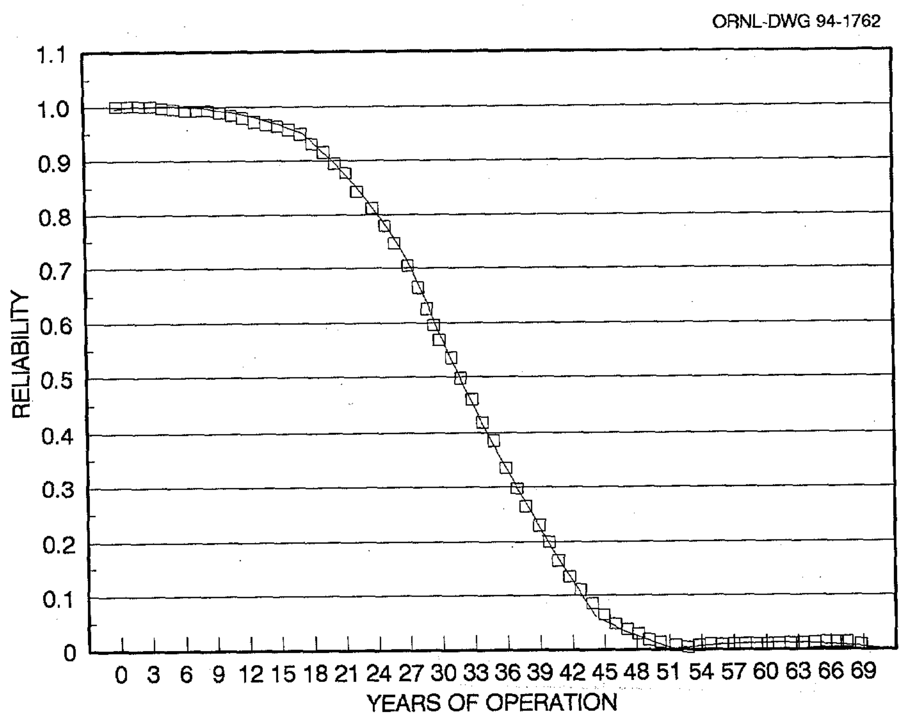

Fig. D.1. Reliability of distribution transformers fitted to Weibull distribution.

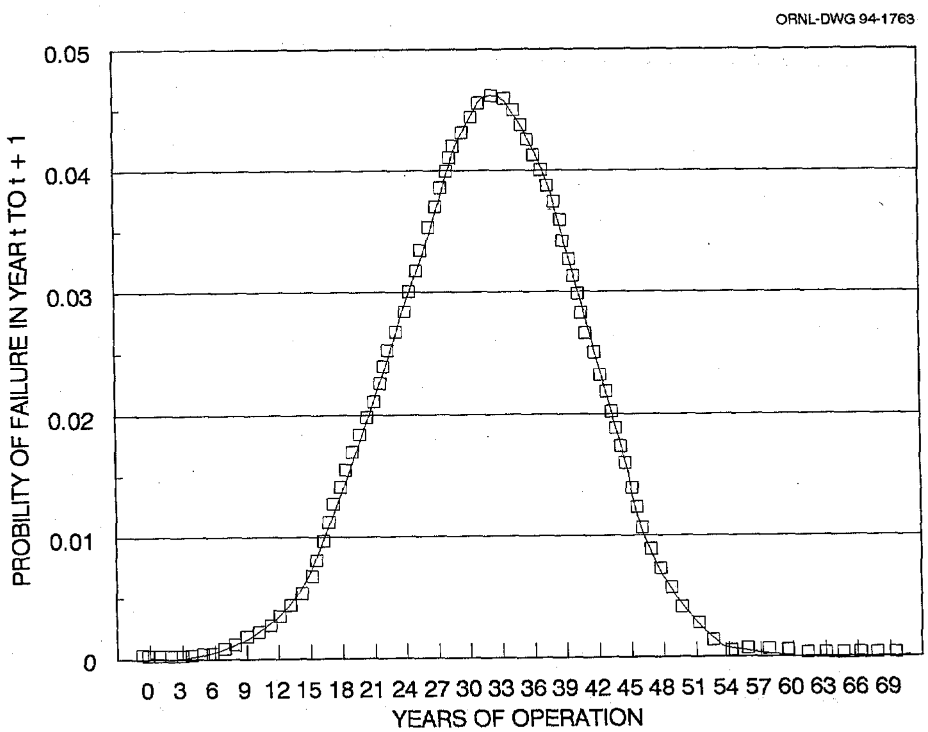

Fig. D.2. Probability density $f(t) = -dR/dt$, where R is the Weibull distribution of Fig. D.1.

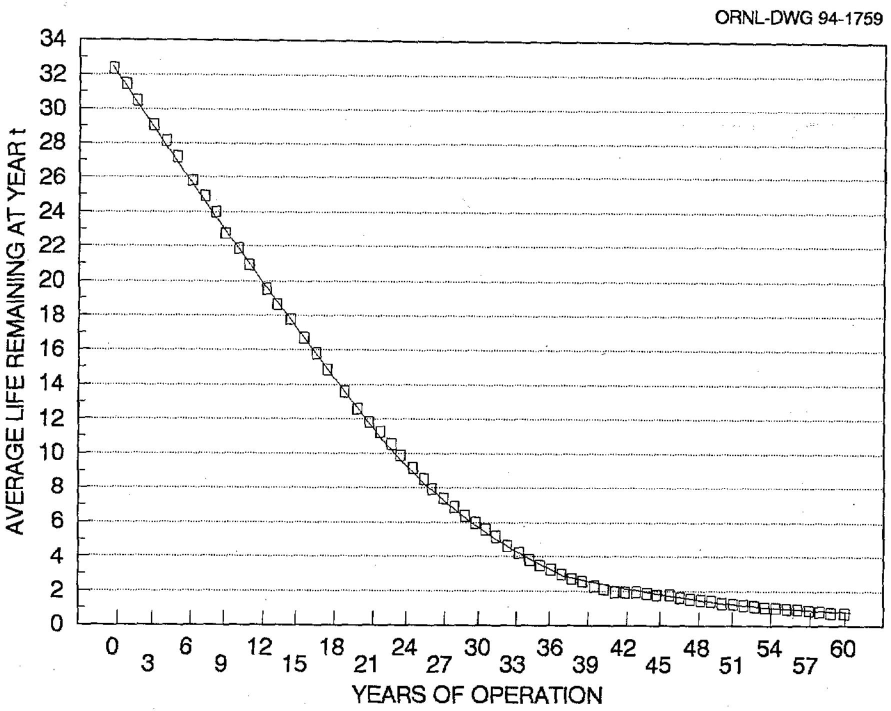

Fig. D.3. Average life remaining at year *t* for the Weibull distribution in Fig. D.1.

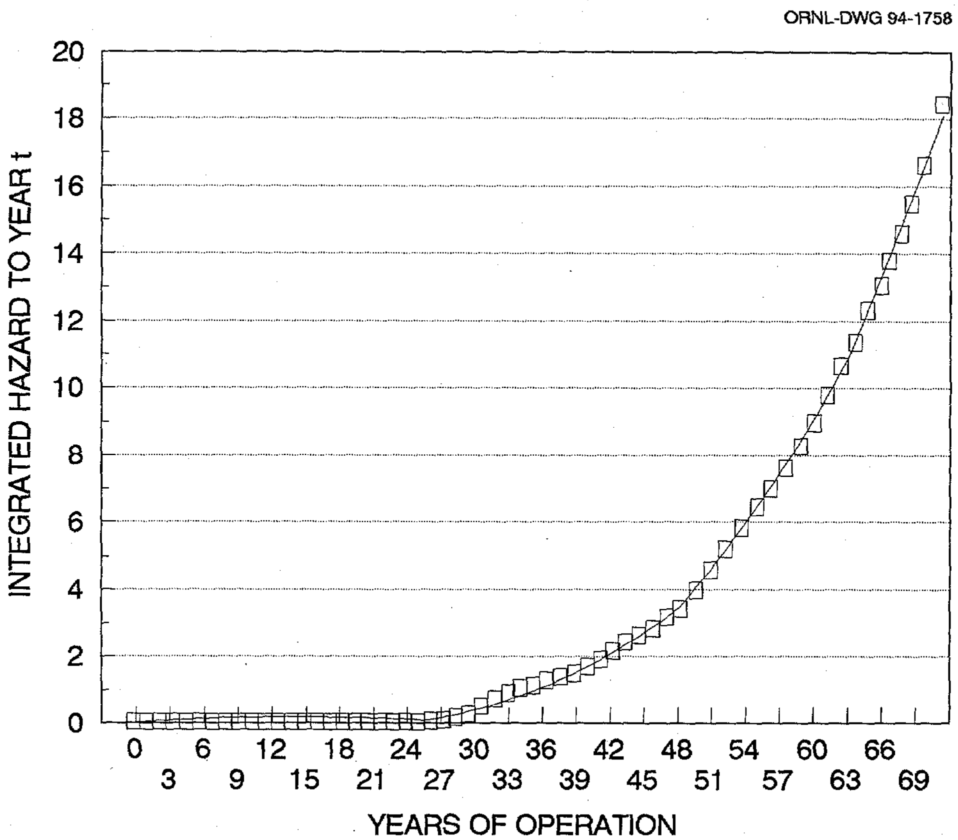

Fig. D.4. Cumulative failure rate or hazard function.

APPENDIX E

ASSUMPTIONS USED IN EVALUATING LIFE CYCLE COSTS

APPENDIX E

Assumptions Used in Evaluating Life Cycle Costs

For purposes of discussing the assumptions used to evaluate the LCC of early replacement of distribution transformers, we have categorized these assumptions as follows: economic assumptions that are used to evaluate the losses (Section E.1), assumptions that describe the remaining life and costs of refurbished transformers (Section E.3), and price (new transformers) and performance assumptions (new and refurbished transformers) (Section E.4). Section E.2 discusses the alternative perspectives that result in different loss evaluation formulas between utilities and the rationale for the national perspective that is taken for this study.

In cooperation with this study, the Edison Electric Institute (EEI) sent a distribution transformer survey to a selection of its investor-owned utility members. Responses to this survey represented about 33 percent of the total on-line distribution capacity of all utilities (public and private). A similar survey was sent by the American Public Power Association, which represents municipal utilities, to a selection of its members. The responses to the survey by the investor-owned utilities tended to be much more complete; the generally smaller municipal utilities had less detailed records of transformer activities. Therefore, only the results of the survey of investor-owned utilities were used in this study. On the basis of this survey, we estimated the composition of distribution transformers by type and size, the percentage of retirements and refurbishments within total distribution transformer stock, the refurbishment of transformers by age, the average cost and losses of recently purchased transformers, and average costs of refurbishment and reinstallation of transformers by size and type. The survey also reported A and B factors for a large number of respondents.

E.1 Assumptions Used to Develop the Loss Evaluation Parameters (A and B Factors)

The basic approach in developing loss evaluation formulas was to follow procedures outlined by IEEE Loss Evaluation Guide for Power Transformers and Reactors (IEEE Std C57.120),[1] by an Edison Electric Institute 1981 report prepared by a task force of the EEI Transmission and Distribution Committee,[2] and in two articles by D. L. Nickel and H. R. Braunstein on distribution transformer loss evaluation.[3,4] These various publications differ somewhat in the details of estimating the value of transformer losses, but conceptually they are similar and lead to very similar results.

The loss evaluation methodologies consider the costs that are related to the energy losses of the distribution transformer. These costs are often expressed in the cost per watt of no-load losses (the A factor) and the cost per watt of load losses (the B factor). The no-load losses are the core losses of the transformer and are constant over time as long as the transformer is energized. Therefore, if no-load losses of a transformer are 100 watts, or

0.1 kW, they occur 8760 h per year. Two electric system components need to be considered: capacity costs and production costs. For the purposes of this assessment, no-load losses are assumed to be served by base load capacity, since this is the type of capacity that is in service 100 percent of the year. Base load capacity on a generating system is typically the most economical generating unit in terms of energy cost per kilowatt-hour served. For instance, a utility may have a peak load of 10,000 MW that it serves only 1 h during the year and a base load of 4000 MW that it must meet for all 8760 h of the year. Generally the 4000-MW base load will be served by capacity such as coal or nuclear power. Base load capacity has relatively high capital costs per kilowatt but relatively low fuel, operating, and maintenance costs per kilowatt-hour. The A factor is calculated as follows:

$$A \text{ factor} = [CSYSB + (CEBL \times 8760)/CC] \times 1/1000,$$

where

$CSYSB$ = incremental cost of system base load per kilowatt,
CC = annual carrying charge rate on capital,
$CEBL$ = levelized production cost for base load capacity per kilowatt hour,
8760 = hours in a year,
1/1000 = conversion from kilowatts to watts.

Substituting with assumptions detailed in this section,

$$A = [\$958 + (\$0.028 \times 8760)/0.0956] \times 1/1000$$

$$A = \$3.53$$

E.1.1 System base load capacity costs assumed in estimating the A factor

The cost of the system base load is based on the assumption that a kilowatt of new base load capacity, including interest during construction, is $1792. This is overnight construction for a bituminous, medium-sulfur coal-fired power plant,[5] plus allowance for funds used during construction. However, this has been adjusted down to $1277 because it has been assumed that on a national basis, base load capacity is not in short supply for five years. The adjustment is based on the $1792 cost five years in the future discounted to a present value at 7 percent. A further downward adjustment was made to $958 by multiplying by 0.75 to reflect the adjustment in incremental capacity that would occur in changing the size of a new plant. For instance, the average cost of an additional 50 MW added to a 600-MW plant would be less than the average cost per megawatt of the full plant.

Carrying charge or fixed charge rate on capital. The capital carrying charge is based on a real interest rate of 7 percent, and a 30-year depreciation life plus 1.5 percent for insurance and retirement dispersion, for a total of 9.6 percent. The interest rate is based on the discount rate required by OMB Circular A-94.[6] This discount rate has been adjusted by OMB to include some provision for earning a return to meet federal and local taxes that private businesses must pay as well as the cost of capital they pay for debt and equity. *This is a real rate and therefore does not include provision for inflation, which normally increases the fixed charge rate that utilities use to account for their levelized capital costs.* Even so, the real rate may be somewhat lower than the real rate a privately owned utility would use for its assessment based on current costs of capital and taxes. Also, this rate reflects costs associated with delivering energy to the transformer.

Inflation will tend to increase the nominal cost of capital, which is an important component of the carrying charge. An investor-owned utility's carrying charge will tend to be 12 percent or more. However, the net effect of general inflation should be small if all economic factors are appropriately adjusted. Still, there may be a real difference in the OMB assumption and a utility's assumptions. The differences in carrying charge will tend to be lower for municipal and rural cooperative utilities because they do not make profits and thus do not pay income taxes; in addition, some publicly owned utilities may finance capital at lower rates through tax-exempt bonds. Higher carrying charge rates will reduce the capitalization of energy costs and result in lower loss evaluations. For instance, using the same set of assumptions, a 10 percent carrying charge will result in a no-load loss of $3.52, compared to $4.12 for an 8.1 percent carrying charge. A 6 percent carrying charge would result in a no-load A factor of $5.23.

Apart from establishing the value of transformer losses, the capital carrying charge also provides the basis for evaluating costs related to capital expenditures for the new transformer. This carrying charge is assumed to be somewhat lower than has been used to value transformer losses. We assume a carrying charge of 8.6 percent, which reflects only the 7 percent real interest rate recommended by OMB, depreciation, and 0.5 percent for retirement dispersion. Although a utility may usually include other costs such as operation and maintenance (O&M) and insurance in its assessment of distribution transformers, this study does not look at increasing the stock of transformers; rather, it assesses replacing one transformer with another of equal size and capability. Therefore, only costs that are actually different between a new and refurbished transformer are included as part of the fixed charge rate. For this analysis it is assumed that apart from refurbishment, take-down, and reinstallation costs, the two alternatives have identical nonenergy O&M costs.

System base load energy costs assumed in estimating the A factor. The levelized incremental production cost used to determine the A factor is 2.8 cents/kWh. This includes a starting fuel cost of 1.9 cents/kWh with a 1.7 percent annual real rate of escalation and an incremental O&M cost of 0.6 cents/kWh with no real escalation. This is based on the average production cost of fossil steam plants for utilities filing FERC Form One for 1991[7] and the real rate of escalation projected for fossil steam fuel (reference case projection of annual growth) from 1992 to 2010 for the price of steam coal for electric utilities.[7] All costs have been converted to 1993 dollars using the implicit gross domestic product (GDP) price deflator.

E.1.2 Assumptions used in estimating the unit cost of load losses (B factor)

The cost per watt of load losses (the B factor) is assumed to be associated with the costs of the electrical system's peaking capacity. In contrast to no-load losses, which occur 100 percent of the time, load losses of a distribution transformer fluctuate with the load that is placed on the transformer. Most of the load on the transformer will occur during periods when the generation and transmission system also experience the heaviest demand for producing and transmitting power. Therefore, the capacity and production costs of the system's peaking capacity will be used to calculate the cost of load losses.

B factor = load loss demand cost + load loss energy cost

Load loss demand cost = $CSYSP \times (PRFS \times PEQO)^2$

Load loss energy cost = $(8760 \times LSF \times CEPL \times PEQE^2) \, / \, CC$,

where

$CSYSP$ = incremental cost of system peak capacity per kilowatt,
$PRFS$ = peak load responsibility factor for system,
$PEQO$ = transformer annual equivalent peak load without energy inflation,
8760 = hours in a year,
LSF = loss factor,
$CEPL$ = levelized peak load energy costs,
$PEQE$ = transformer annual equivalent peak load with energy inflation,
CC = carrying charge.

Substituting:

Load loss demand cost = $(\$410 \times [0.75 \times 0.961]^2) \times 1/1{,}000 = \$0.21$

Load loss energy cost = $[(8{,}760 \times 0.135 \times \$0.07 \times 1.416) \, / \, 0.0956] \times 1/1{,}000 = \$1.23$

B factor = $\$0.21 + \$1.23 = \$1.44$

System peak energy production costs. The levelized incremental production cost used to determine the B factor is 7.0 cents/kWh. This includes a starting fuel cost of 3.3 cents/kWh with a 3.3 percent annual real rate of escalation and an incremental O&M cost of 2.4 cents/kWh with no real escalation. This is based on the average production cost of fossil steam plants for utilities filing FERC Form One for 1991[7] and the real rate of escalation (reference case projection of annual growth) from 1992 to 2010 for the price of natural gas for electric utilities.[7] All costs have been converted to 1993 dollars using the implicit GDP price deflator.

System peak capacity costs. The incremental cost of a system's peak capacity includes the cost of generating peak capacity per kilowatt plus the cost of the T&D systems (prior to entering the primary side of the transformer) per kilowatt. The peak generation capacity is taken as $382 per kilowatt, assuming a gas combustion turbine.[5] The transmission cost was assumed to be $117 per kilowatt, and the distribution costs per kilowatt, not including costs associated with the distribution transformers, were assumed to be $47. The T&D costs reflect costs derived from the relevant asset values reported in *Financial Statistics of Major Investor-Owned Electric Utilities, 1991*,[8] and part of the O&M costs for these systems. The total of these components (including fractions not shown) is $547, but because the system costs reflect average costs, this was adjusted downward to $410 by using a factor of 0.75 to reflect that the addition of an increment to capacity usually costs somewhat less than average costs for new capacity.

The peak load responsibility factor for the system relates the responsibility of the peak load on the transformer to the peak load on the systems capacity. Because of the diversity in the pattern of electricity use among customers, it is unlikely that the peak load on the transformer will occur at exactly the same time as the peak load on the system. This results in the transformer's contribution to system peak load being somewhat less than the peak load on the transformer—i.e., a peak load responsibility factor of less than 1.0. As the number of customers on a transformer increases, the diversity of their demands on the transformer tends to more closely reflect the average diversity of demand across the electric system that results in the peak demand on the system. It follows that the peak load responsibility factor will tend to approach 1.0 as the number of customers on the transformer increases and decrease as the number of customers on the transformer decreases. Therefore, smaller transformers with fewer customers will tend to have lower peak load responsibility factors than larger transformers that serve a larger number of customers. The factor used to reflect the peak load responsibility factor is 0.75.[3]

Loss factor and levelized peak load. The loss factor relates the average transformer power losses to the peak loss. During periods when the transformer is more heavily loaded, its energy losses increase with the square of the power loss. Because of the wide range of the power demand made on a transformer over a year, the average losses will be a relatively small fraction of what they are at the time of the peak demand on the transformer. The loss factor will tend to increase somewhat with the number of customers on the transformer. The 0.135 value used in the calculation above corresponds to the range of a 25-kVA to 50-kVA transformer with 12 customers.[3]

The terms *PEQO* and *PEQE* are economic factors that levelize the annual peak load. The former accounts for growth in the peak load but not for increases related to production costs (such as real fuel escalation). The *PEQE* factor levelizes peak load on the transformer, accounting for both growth in the peak load over time and growth in production costs. The *PEQO* levelizing factor is applied to capacity costs that remain fixed after the investment is made. The *PEQE* factor is used to levelize the peak transformer load with respect to energy costs, which are assumed to escalate over time.[4]

E.2 Loss Evaluation Assumptions—National Versus Utility Perspectives

The assumptions in Section E.1 have been developed to reflect a national perspective on the early replacement of transformers. Several points should be considered about the differences between the national perspective developed in this study and the "utility perspective." This is an important difference to recognize because it is one basis for recommending changes in the current utility refurbish/replace decision. In order to recognize the variation in perspectives, a sensitivity analysis is performed in Section 5.1.

One common observation made by transformer manufacturers, and supported by the industry survey, is that the purchase and replacement decisions made by utilities reflect a wide diversity of specific conditions. Utilities attempt to reconcile their decisions on distribution transformers with the specific conditions of their situation, as opposed to average utility or national conditions. Even where utilities face very similar economic conditions and customer demand patterns, they may have different strategies for loading their transformers, or make different assumptions about transformer loads because of uncertainty and/or lack of better information.

An attempt to portray the national perspective on the energy and capacity costs associated with distribution transformers has been developed in the previous section on loss evaluation coefficients. This perspective assumes that the costs and benefits associated with higher or lower transformer efficiencies can be approximated through an economic analysis using average values. It is recognized that different utilities and different regions face significantly different capacity and energy costs that go into the A and B factors used in the loss cost formula. In addition, the time-values of money (discount rates) vary between investor-owned utilities and public utilities and both vary from OMB estimates, as noted. However, energy and capacity can be exchanged between utilities and regions of the country. In this sense, capacity and energy savings from using more efficient distribution transformers can become part of a larger market for capacity and generation through interconnected transmission systems that wheel power over a wide area. Therefore, from a social perspective a broad evaluation of transformer losses and costs using average national values for capacity and energy may be more appropriate for evaluating distribution transformers than the sum of the specific evaluations done by utilities. This type of argument cannot be applied to other variables, such as loading practices, that also affect the loss formula.

Economic parameters and loading practices are included in the calculation of the A and B factors and in refurbishment and installation costs. The industry survey reported a wide range of these economic parameters. This is not surprising because utilities face different fuel, capital, and maintenance costs. Also contributing to a difference in the B factor is whether a utility tends to load a distribution transformer heavily, since this practice results in higher load losses and a shorter transformer life. Despite the reduction of transformer life and higher load losses, this can be a cost-effective strategy because it allows the utility to use a smaller transformer that has a lower capital cost. And because it is relatively small, the transformer tends to have lower no-load losses. Another utility strategy that contributes to different cost of losses, especially in rural areas or where transformer load factors are low, is to purchase transformers with relatively low no-load losses but high load losses. This may be an effective strategy where most of the transformer's losses are associated with the no-load component. In order to make cost-effective decisions, utilities must account for trade-offs between no-load losses, load losses, initial transformer cost, and transformer life. Correctly accounting for these factors is necessary to make cost-effective transformer purchases.

In addition to economic factors, different climatic conditions result in different transformer requirements. For instance, the wet, salty environment in coastal areas may result in shorter transformer life and/or more frequent maintenance requirements. Other areas have frequent lightning strikes, resulting in shorter average transformer life and the need for surge protection equipment, and thus, higher transformer costs.

Most large utilities evaluate their transformer decisions using A and B factors as discussed in this section. These A and B factors differ widely. For instance, the unweighted average A and B factors for 55 investor-owned utilities were \$3.05 and \$0.87 per watt, respectively. However, 20 percent had A factors below \$2.50 and 20 percent had A factors above \$3.91. For B factors, 20 percent were below \$0.48 and 20 percent above \$1.54. Besides the difference in A and B factors, utilities in the survey have reported widely varying costs of refurbishment and take-down and reinstallation. These costs can also make a crucial difference in a utility's perspective on refurbishment versus replacement. One conclusion from the variation of factors that are utility-specific is that there is no one "utility perspective" but that there are as many utility perspectives as there are utilities that have significantly different economic parameters and transformer loading practices.

Finally, from the utility's perspective, transformers of the same size and type have individual characteristics that must be considered in evaluating the need to refurbish or replace. Many utilities have age requirements of 25 to 30 years, beyond which they will not refurbish a transformer that has been brought off the lines. Others have age criteria that consider not only the age but the cost of refurbishment. For instance, a utility may retire any transformer 30 years or older but refurbish transformers that are 20 to 29 years only if the refurbishment cost is less than $150. This is the type of selective refurbishment criteria that may or may not be a formal policy but is an operational procedure based on the judgment of maintenance procedure managers.

In summary, there is no one utility perspective. Utilities have many factors to consider in making decisions about transformers. Many decisions are made based on rules of thumb reflecting the utility's experience. A utility may or may not face "average conditions" with regard to its distribution transformers. Also, transformers within a single utility operate under a diverse set of conditions that may be considered in optimizing refurbishment decisions. At the same time a national perspective based on average conditions can be justified to the extent that it reflects the realities of a market for electric power.

E.3 Remaining Life and Refurbishment Costs

The remaining life of a refurbished transformer is an important assumption for the economic analysis because the present value of capital, refurbishment, take-down, and reinstallation costs are affected when these costs are incurred. In present value calculations, nominal costs are progressively reduced as they occur further in the future because a positive discount rate progressively reduces their present value. Therefore, a refurbished transformer that lasts 15 years compared to five years will have a lower present value cost of its replacement transformer and also lower present value of its take-down and reinstallation costs. Furthermore, the replacement transformer will have a higher residual value at the end of the study period because it will have more years of serviceable life left. The assumption that is made in this analysis is that a transformer's remaining life is a function of its age. Therefore, a 20-year-old transformer would have less remaining life than a 10-year-old transformer. This assumption is more fully explained in Section 3 and Appendix D. The results of the industry survey indicated that about 47 percent of refurbished transformers are less than 10 years old, 34 percent are between 10 to 19 years old, 18 percent are 20 to 29 years old, and about 1 percent are more than 29 years old. Refurbishment, take-down, and reinstallation costs have also been based on the average costs reported by utilities in the industry survey. These costs varied by size and type of transformer. For a 25-kVA transformer, the average cost of refurbishment was $168, with the average cost of take-down and reinstallation being $365.

E.4 Price and Performance of Transformers

The industry survey generated information on what utilities are actually paying for different transformer sizes and types with their associated no-load and load losses. Our assumptions on costs and losses are based on the results of this survey. Refurbished transformers also vary in terms of their no-load and load losses. On average, the no-load and load losses of transformers have tended to be reduced over time as manufacturers gradually improved efficiencies or as utilities increased their willingness to pay premiums for lower-loss transformers. After the early to mid-1970s, many utilities began to evaluate transformer losses, and manufacturers responded with transformers of widely varying losses to accommodate the diversity in utility preferences. Before this period, however, manufacturers of transformers had only a few designs, and similar vintages tended to have similar losses. Therefore, while the losses of transformers vary by manufacturer and transformer design, refurbished transformers are assumed to have losses typical of the vintage they represent. Newer transformers are assumed to have progressively lower losses, reflecting gradually improving efficiencies. These assumptions are based on published or unpublished data supplied by manufacturers where available.* Data on losses for some specific transformer sizes and types were not available for some of the time periods used in the analysis. These assumptions have been made by extrapolating from data points where data were available, using the general trends of improvement. Table E.1 indicates the loss assumptions for size, type, and vintage of the transformers. Table E.2 indicates the average costs, no-load loss, and load loss from the industry survey.

E.5 Rate and Age of Refurbishments

The industry survey indicated that about 1.0 percent of the total installed transformer capacity of utility distribution transformers was refurbished in 1993. This would be about 17 million kVA for the entire nation (see Appendix B). Most utilities did not have readily available information on the age of their refurbished transformers. Based on those reporting, about 47 percent of refurbishment activity occurs on transformers that are less than 10 years old, and about 81 percent occurs on transformers less than 20 years old. Only about 1 percent of total refurbishments (by kVA) occurs on transformers that are 30 years old or older. This indicates that most refurbishments occur on transformers with a significant amount of remaining life and that because of the value of remaining life, most transformers being refurbished could not be replaced cost-effectively. This supports a hypothesis that utilities use an economic rationale in deciding whether to retire and replace transformers that come in for routine maintenance or whether to refurbish them. This decision process tends to implement a

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*The main source for single-phase transformers is Daniel J. Ward and Richard H. Wong, *An Analysis of Loss Measurements on Older Distribution Transformers*, Power Distribution Systems Engineering Operation, General Electric Co., Schenectady, N.Y. This gave composite average industry losses for 7.2-kV voltage class distribution transformers for 10-, 15-, 25-, and 50-kVA transformers For 500-kVA three-phase transformers the 1960 value was taken from the *Electric Utility Engineering Reference Book*, February 1958. Losses for transformers purchased after 1970 were taken from values reported by major transformer manufacturers, and for 1993, from the survey of utility distribution transformers. The later values are probably less reliable than those taken from the General Electric study; however, their accuracy is probably less important to the evaluation because the significant remaining life of newer transformers makes them less economically attractive to replace.

Table E.1. Loss estimates (watts) by vintage and transformer size

	Size (kVA)										
Vintage	10	15	25	37.5	50	75	100	167	225	500	1000
					No-load loss estimates						
1950	75	103	149	201	248	336	417	613	1414	2574	4328
1955	70	95	138	186	230	312	387	568	1311	2387	4014
1960	65	87	127	171	212	287	357	524	1209	2200	3700
1965	60	81	118	159	197	267	331	487	1123	2044	3438
1970	58	79	115	155	192	260	323	474	1095	1992	3351
1975	52	71	103	139	172	233	289	427	942	1716	2890
1980	46	62	90	123	152	205	255	379	790	1440	2429
1985	40	54	78	107	131	177	221	332	639	1163	1968
1993	31	40	58	81	99	133	166	256	396	721	1230
					Load loss estimates						
1950	193	262	383	519	646	876	1086	1596	3318	6315	10156
1955	183	248	363	492	612	830	1029	1512	3143	5982	9622
1960	173	234	343	465	578	783	972	1428	2965	5650	9087
1965	156	211	309	419	521	706	876	1287	2823	5403	8808
1970	141	191	279	378	470	637	790	1161	2680	5156	8529
1975	143	196	286	385	481	655	808	1204	2531	4910	8250
1980	145	201	293	393	491	674	826	1246	2394	4663	7971
1985	147	205	300	400	502	692	844	1288	2251	4416	7692
1993	151	212	312	412	520	718	873	1350	1998	4021	7246

Table E.2. Average transformer costs and losses for recent purchases of new transformers

Transformer type and size (kVA)		Av. cost of new transformer	Av. no-load losses (watts)	Av. load losses (watts)	Av. cost of refurbishment	Av. cost of take-down and reinstallation
Pole type	10	$396	31	151	$130	$339
	15	$450	40	212	$137	$370
	25	$543	58	312	$168	$365
	37.5	$671	81	412	$168	$422
	50	$777	99	520	$220	$409
Pad type	50	$1,129	98	536	$309	$533
	75	$1,406	133	718	$309	$533
	167	$2,264	256	1,350	$314	$623
Three-phase	225	$4,892	396	1,998	$755	$926
	500	$7,197	721	4,021	$1,346	$1,410
	1000	$11,503	1,230	7,246	$1,346	$1,410

distribution transformer policy that already leans heavily in the direction of early replacement. In addition, with each passing year, this policy pushes the distribution transformer population to overall lower losses by retiring the oldest, least efficient units. The survey indicates that many utilities are replacing transformers that are over 20 years old rather than refurbishing them. Besides the reported age of refurbished transformers, the survey also tended to support this conclusion in that many utilities reported an age criterion of between 20 and 30 years beyond which they would not consider a transformer for refurbishment.

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